SANDRIDGE ENERGY INC
Form 10-K
February 28, 2014

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, 2013
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 þ No ¨
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No 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 þ	Accelerated filer o
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 28, 2013 was approximately $2.3 billion based on the closing price as quoted on the New York Stock Exchange. As of February 21, 2014, there were 495,085,274 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company's definitive proxy statement for the 2014 Annual Meeting of Stockholders are incorporated by reference in Part III.

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2013 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 25.

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 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;
- economic viability of certain natural gas production in west Texas due to high CO_2 content;
- risks associated with obligations to deliver minimum volumes of natural gas and/or CO_2 under long-term contracts;
- 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;
- 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 need to maintain adequate internal control over financial reporting.

PART I

Item 1. Business

GENERAL

SandRidge Energy, Inc. is an oil and natural gas company with a principal focus on exploration and production activities in the Mid-Continent region of the United States. The Company owns and operates additional interests in west Texas and owned interests in the Gulf of Mexico and Gulf Coast until February 2014, as discussed under “2014 Divestiture” below.

As of December 31, 2013, the Company had 4,388 gross (3,246.7 net) producing wells, a substantial portion of which it operates, and approximately 3,624,000 gross (2,438,000 net) total acres under lease. As of December 31, 2013, the Company had 30 rigs drilling in the Mid-Continent, one rig drilling in the Gulf of Mexico and three rigs drilling in west Texas. Total estimated proved reserves as of December 31, 2013 were 433.4 MMBoe, of which approximately 64% 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 disposal system, an electrical transmission system and a drilling rig and related oil field services business. As of December 31, 2013, the Company’s drilling rig fleet consisted of 27 operational rigs. These complementary businesses provide the Company with operational flexibility and an advantageous cost structure by reducing its dependence on third parties for the services provided by these businesses.

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 region of the United States. The sale of its Gulf of Mexico and Gulf Coast oil and natural gas properties, discussed under “2014 Divestiture” below, represents a major step toward the achievement of that mission, by positioning SandRidge as a liquid-rich Mid-Continent company. In pursuit of its mission, the Company focuses on the following strategies:

- Concentrate in Core Operating Area. The Company’s primary area of operation is the Mid-Continent area of Oklahoma and Kansas. By concentrating in this core area, the Company is able to (i) further build and utilize its technical expertise in order to interpret 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 produced water disposal systems and (iv) opportunistically grow its holdings through acquisitions, farmouts and operations in this area to achieve production and reserve growth. Additionally, as operator of a majority of its wells, the Company has flexibility to utilize these competitive advantages to deliver strong, sustainable returns.
- Develop Key Infrastructure Systems. By constructing a produced water 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.

- 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 area. 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 completion designs, well site production facilities, utilization of pad drilling and spud-to-spud cycle time to further reduce its cost structure in the Mid-Continent.

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- Focus on Reservoirs with Known Hydrocarbon Production. The Company focuses its development efforts primarily in conventional, shallow, low-cost, permeable carbonate reservoirs with decades of production history. The nature of these reservoirs allows the Company to execute low-risk, repeatable drilling programs with predictable production profiles and a higher certainty of economic returns. Further, due to these low pressure and shallow characteristics, the Company is able to maintain a low-cost operating structure and manage service costs.
- Maintain Flexibility. The Company has multi-year inventories of both oil and natural gas drilling locations within its core operating area. Additionally, the Company maintains its own fleet of drilling rigs through its wholly owned drilling rig business. Maintaining inventories of both oil and natural gas drilling locations as well as its own drilling rigs allows the Company to efficiently direct capital toward projects with the most attractive returns.
- Mitigate Commodity Price Risk. The Company enters into derivative contracts to mitigate 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.
- Pursue Opportunistic Acquisitions. The Company periodically reviews acquisition targets to complement its existing asset base. Accordingly, the Company selectively identifies such targets based on several factors including relative value, hydrocarbon mix and location and, when appropriate, seeks to acquire them at a discount to other opportunities.
- Asset Monetization. The Company periodically evaluates its properties to identify opportunities to monetize assets to fund or accelerate development within its area of focus, and may use proceeds realized from such transactions to fund the drilling and development of its core area, for general corporate purposes or to retire corporate debt.

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 has used and expects to use the remaining proceeds to fund its 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.

2014 Divestiture

Sale of Gulf of Mexico and Gulf Coast Properties. On February 25, 2014, the Company sold certain of its subsidiaries that own the Company’s Gulf of Mexico and Gulf Coast oil and natural gas properties (collectively, the “Gulf Properties”), for $750.0 million, subject to purchase price and post-closing adjustments, and the buyer’s assumption of approximately $370.0 million of related asset retirement obligations. Under the agreement, the Company agreed to guarantee certain plugging and abandonment obligations associated with the Gulf Properties on behalf of the buyer for a period of up to one year. Additionally, as part of the agreement, the buyer has agreed to indemnify the Company for any costs it may incur as a result of the guarantee. The Company retained a 2% overriding royalty interest in certain exploration prospects. The Company expects to use the proceeds from the sale to fund its drilling in the Mid-Continent.

At December 31, 2013, the Gulf Properties had associated proved reserves of 56.8 MMBoe with an estimated PV-10 value of $1.1 billion. See discussion of PV-10 under “—Proved Reserves.” For a reconciliation of PV-10 to Standardized Measure of Discounted Net Cash Flows (“Standardized Measure”), see “Management’s Discussion and Analysis -

Overview" in Item 7 of this report. The estimated Standardized Measure attributable to the Gulf Properties was approximately $842.5 million at December 31, 2013. For the year ended December 31, 2013, production, revenues and expenses, including direct operating expenses, depletion, accretion of asset retirement obligations and general and administrative expenses, for the Gulf Properties were 10.1 MMBoe, $627.2 million and $492.0 million, respectively.

BUSINESS SEGMENTS AND PRIMARY OPERATIONS

The Company operates in three business segments: exploration and production, drilling and oil field services and midstream services. Financial information regarding each segment is provided in Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Note 22—Business Segment Information” to the Company’s consolidated financial statements in Item 8 of this report. The information below includes the 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.

Exploration and Production

The Company explores for, develops and produces oil and natural gas, with a primary focus on increasing its reserves and production in the Mid-Continent. The Company operates substantially all of its wells in this area and also operates wells and owns leasehold positions in west Texas and owned interests in the Gulf of Mexico and Gulf Coast until February 2014.

The following table presents information concerning the Company’s exploration and production activities by geographic area of operation as of December 31, 2013, 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	302.3	$ 3,427.4	52.1	15.9	2,621,018	1,849,244	$ 945.0
Gulf of Mexico / Gulf Coast	56.8	1,088.9	24.7	6.3	882,934	494,069	197.1
West Texas	74.3	675.3	11.9	17.1	120,217	95,170	198.2
Total	433.4	$ 5,191.6	88.7	13.4	3,624,169	2,438,483	$ 1,340.3

(1) For a reconciliation of PV-10 to Standardized Measure, see “—Proved Reserves.” The Company’s total Standardized Measure was $4.0 billion at December 31, 2013.
(2) Average daily net production for the month of December 2013.
(3) Estimated net proved reserves as of December 31, 2013 divided by production for the month of December 2013 annualized.
(4) Capital expenditures for the year ended December 31, 2013 on an accrual basis.

Properties

Mid-Continent

The Company held interests in approximately 2,621,000 gross (1,849,000 net) leasehold acres primarily in Oklahoma and Kansas at December 31, 2013. Associated proved reserves at December 31, 2013 totaled 302.3 MMBoe, 60% 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, 2013 included 1,858 gross (1,038.5 net) producing wells with an average working interest of 56%. The Company had 30 rigs operating in the Mid-Continent as of December 31, 2013, of which 26 were drilling horizontal wells, three were drilling vertical wells and one was drilling a saltwater disposal well. The Company drilled a total of 434

horizontal wells, 49 vertical wells and 28 saltwater disposal wells in this area during 2013.
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 Kansas. The top of this formation is encountered between approximately 4,000 and 7,000 feet and lies stratigraphically between the Pennsylvanian-aged Morrow formation and the Devonian-aged Woodford Shale formation. The Mississippian formation can reach 1,000 feet in gross thickness and the targeted porosity zone is between 50 and 100 feet in thickness. At December 31, 2013, the Company had approximately 2,535,000 gross (1,805,000 net) acres under lease in the Mississippian formation, of which approximately 58,000 gross (46,000 net) acres were included in the Mississippian Trust

II area of mutual interest. As the Company fulfilled its drilling obligation to the Mississippian Trust I in April 2013, the associated area of mutual interest terminated.
The Company has drilled approximately 1,060 wells in this formation as of December 31, 2013. From December 31, 2012 to December 31, 2013, the number of the Company's producing horizontal wells in the Mississippian formation increased from 649 to 1,167. Of the wells the Company drilled in the Mississippian formation during 2013, 86 wells are subject to the royalty interests of the Mississippian Trust I or Mississippian Trust II.
The Company's saltwater disposal system, constructed beginning in 2007, and electrical infrastructure, constructed by the Company's midstream services segment beginning in 2009, assist in the economically efficient production of oil and natural gas in the Mid-Continent. The saltwater disposal system, which included more than 150 active wells and approximately 865 miles of gathering lines at December 31, 2013, reduces the overall cost of water disposal, which directly reduces production costs. The Company's electrical infrastructure, which consisted of approximately 780 miles of power lines and five substations at December 31, 2013, 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.

Gulf Properties

The Company's Gulf Properties include oil and natural gas properties in the Gulf of Mexico and the Gulf Coast. The Company's Gulf of Mexico operations, a substantial portion of which were acquired during the second quarter of 2012 with the acquisition of Dynamic Offshore Resources, LLC (the "Dynamic Acquisition") and other Gulf of Mexico properties, primarily extend from the coast to more than 100 miles offshore and occur in federal and state waters with depths ranging from 10 to 1,380 feet. The Company's Gulf of Mexico oil and natural gas properties are shallow-water assets, with the exception of the Bullwinkle field, which is a deepwater asset. Additionally, the Company owns oil and natural gas interests in the Gulf Coast area, which encompasses the coastal plain from the southernmost tip of Texas through the southern portion of Louisiana.

As of December 31, 2013, the Company's Gulf Properties consisted of approximately 883,000 gross (494,000 net) leasehold acres, 634 gross (370.0 net) productive wells and approximately 350 miles of pipeline gathering systems. Associated proved reserves at December 31, 2013 were approximately 56.8 MMBoe, of which 70% were proved developed. The Company operates approximately 97% of these assets, based on PV-10 values as of December 31, 2013. The Company had one rig operating in the Gulf Properties as of December 31, 2013. In the Gulf Properties, the Company drilled a total of seven operated wells, participated in the drilling of four non-operated wells, performed 19 operated recompletions and participated in 14 non-operated recompletions during 2013.

The Company's pipeline gathering systems in the Gulf of Mexico, including the Bullwinkle platform, which serves as a processing hub for deepwater production, gather and transport production from third-party fields for which the Company receives production handling revenues.

As discussed in "2014 Divestiture" above, the Company sold its Gulf Properties and related pipeline gathering systems in February 2014.

West Texas

The Company's west Texas oil and natural gas properties include properties in the Permian Basin and the West Texas Overthrust ("WTO"). In February 2013, the Company sold all of its oil and natural gas properties in the Permian Basin, other than those assets attributable to the Permian Trust's area of mutual interest. The Permian Basin extends throughout southwestern Texas and southeastern New Mexico and is one of the largest, most active and longest-producing oil basins in the United States. The WTO is an area located in Pecos and Terrell Counties in west

Texas and is associated with the Marathon-Ouachita fold and thrust belt that extends east-northeast across the United States into the Appalachian Mountain Region.

The Company held interests in approximately 120,000 gross (95,000 net) leasehold acres in west Texas at December 31, 2013, of which approximately 16,000 gross (15,000 net) acres were included in the Permian Trust’s area of mutual interest. Associated proved reserves at December 31, 2013 were 74.3 MMBoe, 77% of which were proved developed reserves. The Company’s interests in west Texas as of December 31, 2013 included 1,896 gross (1,838.2 net) producing wells with an average working interest of 97%. The Company had three rigs operating in west Texas as of December 31, 2013 and drilled 213 wells in this area during 2013, of which 202 were subject to the Permian Trust’s royalty interest. Low natural gas prices continued to limit development activity in the WTO, primarily a natural gas-producing region, during 2013.

Pursuant to a 30-year treating agreement with Occidental Petroleum Corporation (“Occidental”), the Company delivers natural gas produced in the WTO to Occidental’s CO_2 treatment plant in Pecos County, Texas (the “Century Plant”), and Occidental removes CO_2 from the Company’s delivered production volumes of natural gas. The Company retains all methane gas after treatment. Under the agreement, the Company is required to deliver a total of approximately 3,200 Bcf of CO_2 during the agreement period. At December 31, 2013, approximately 3,000 Bcf of CO_2 remained to be delivered. The Company is obligated to pay Occidental $0.25 per Mcf to the extent minimum annual CO_2 volume requirements are not met. Additionally, if CO_2 volumes delivered by the Company over the term of the agreement do not reach 3,200 Bcf, the Company is obligated to pay Occidental $0.70 per Mcf for such undelivered CO_2 volumes at the end of the agreement term in 2042. Based upon natural gas production levels in 2013, the Company accrued $32.7 million for amounts related to the Company’s shortfall in meeting its 2013 annual delivery obligations, which was included in production expense for the year ended December 31, 2013. Based on current projected natural gas production levels, the Company expects to accrue between approximately $30.0 million and $37.0 million during the year ending December 31, 2014 for amounts related to the Company’s anticipated shortfall in meeting its 2014 annual delivery obligations. Due to the sensitivity of drilling activity to market prices for natural gas, the Company is unable to estimate additional amounts it may be obligated to pay under the agreement in subsequent periods; however, if natural gas prices remain low, drilling activity will likely remain very limited, which would result in additional shortfall payments in future periods.

Proved Reserves

Preparation of Reserve Estimates

The estimates of oil, natural gas and NGL reserves in this report are based on reserve reports, substantially all 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. 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 mandated 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 person 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 28 years of estimating and evaluating reserve information. In addition, SandRidge’s Senior Vice President—Corporate Reservoir Engineering has 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 17 full-time employees, comprised of five degreed engineers and 12 engineering analysts/technicians with a minimum of a four-year degree in mathematics, economics, finance or other business or science field.

The Company maintains a continuous education program for its engineers and technicians 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 Reservoir Engineering Department 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 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. In the event the quarterly updated reserves estimates are disclosed, the aforementioned review process is evidenced by signatures from the Senior Vice President—Corporate Reservoir Engineering and the Chief Financial Officer.

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, Vice President 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 table below shows the percentage of the Company's total proved reserves for which each of the independent petroleum consultants prepared reports of estimated proved reserves of oil, natural gas and NGLs for the years shown.

	December 31,		
	2013	2012	2011
Cawley, Gillespie & Associates, Inc.	64.6 %	— %	— %
Netherland, Sewell & Associates, Inc.	21.5 %	72.7 %	80.5 %
Lee Keeling and Associates, Inc.	— %	24.9 %	15.6 %
Total	86.1 %	97.6 %	96.1 %

The remaining 13.9%, 2.4% and 3.9% of the Company's estimated proved reserves as of December 31, 2013, 2012 and 2011, 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 substantially all geographic locations as of December 31, 2013 are filed with this report as Exhibits 99.1 and 99.2. The geographic location of the Company's estimated proved reserves prepared by each of the independent petroleum consultants as of December 31, 2013 is presented below.

	Geographic Locations—by Area by State
Cawley, Gillespie & Associates, Inc.	Mid-Continent - KS, OK
	Permian Basin—TX
Netherland, Sewell & Associates, Inc.	Gulf of Mexico
	Gulf Coast—LA, 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 26 years of practical experience in petroleum engineering and more than 24 years of experience estimating and evaluating reserve information;
- a registered professional engineer in the state of Texas; and
- a Bachelor of Science Degree in Petroleum Engineering.

Netherland, Sewell & Associates, Inc.

- practical experience in petroleum engineering ranging from more than 14 years to more than 25 years and experience estimating and evaluating reserve information ranging from more than nine years to more than 20 years;
- Licensed Professional Engineers in the states of Texas and Louisiana and Licensed Professional Geoscientists in the State of Texas; and
- Bachelor of Science Degree in Civil Engineering, Bachelor of Science Degree in Mechanical Engineering, Bachelor of Science Degree in Geology, Master of Science Degree in Geology and Master of Business Administration Degree.

Lee Keeling and Associates, Inc.

- more than 57 years of practical experience in petroleum engineering and more than 53 years estimating and evaluating reserve information;
- a registered professional engineer in the state of Oklahoma; and
- a Bachelor of Science Degree in Petroleum 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.

Reporting of Natural Gas Liquids

Natural gas liquids, or NGLs, are produced as a result of the processing of a portion of the Company’s natural gas production stream. At December 31, 2013, NGLs comprised approximately 14% 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, 2013, 2012 and 2011, substantially all 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, 2013, 2012 and 2011, using first-day-of-the-month prices for each month. The Company estimates that approximately 88% of its current proved undeveloped reserves will be developed by the end of 2016 and all of its current proved undeveloped reserves will be developed by the end of 2018. See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

	December 31,		
	2013	2012	2011
Estimated Proved Reserves(1)			
Developed			
Oil (MMBbls)	83.9	136.6	101.6
NGL (MMBbls)	35.8	33.8	17.1
Natural gas (Bcf)	951.6	896.7	670.4
Total proved developed (MMBoe)	278.3	319.9	230.4
Undeveloped			
Oil (MMBbls)	58.7	125.4	112.9
NGL (MMBbls)	23.3	34.2	13.2
Natural gas (Bcf)	438.8	518.3	684.7
Total proved undeveloped (MMBoe)	155.1	246.0	240.2
Total Proved			
Oil (MMBbls)	142.6	262.0	214.5
NGL (MMBbls)	59.1	68.0	30.3
Natural gas (Bcf)	1,390.4	1,415.0	1,355.1
Total proved (MMBoe)(2)	433.4	565.9	470.6
PV-10 (in millions)(3)	$5,191.6	$7,488.4	$6,875.9
Standardized Measure of Discounted Net Cash Flows (in millions)(2)(4)	$4,017.6	$5,840.4	$5,216.3

(1) The Company's estimated proved reserves and the future net revenues, PV-10 and Standardized Measure were determined using a 12-month average price for oil and natural gas. The prices used in the Company's external and internal reserve reports yield weighted average wellhead prices, which are based on index prices and adjusted for transportation and regional price differentials. The index prices and the equivalent weighted average wellhead prices are shown in the table below.

	Index prices		Weighted average wellhead prices		
	Oil (per Bbl)	Natural gas (per Mcf)	Oil (per Bbl)(a)	NGL (per Bbl)	Natural gas (per Mcf)
December 31, 2013	$93.42	$3.67	$95.67	$31.40	$3.65
December 31, 2012	$91.21	$2.76	$91.65	$32.64	$2.29
December 31, 2011	$92.71	$4.12	$91.35	$46.33	$4.06

(a) At December 31, 2013 and 2012, the weighted average wellhead oil price is higher than the index price as a result of favorable location differentials for production in the Gulf of Mexico.

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(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, 2013	29.9	$781.6
December 31, 2012	38.2	$952.7
December 31, 2011	26.4	$932.8

See “Note 24—Supplemental Information on Oil and Natural Gas Producing Activities” to the Company’s consolidated financial statements in Item 8 of this report for additional information regarding reserve and Standardized Measure amounts attributable to noncontrolling interests.

(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using 12-month average prices for the years ended December 31, 2013, 2012 and 2011. PV-10 differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of the Company’s oil and natural gas properties. PV-10 is used by the industry and by the Company’s management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that is not dependent on the taxpaying status of the entity. The following table provides a reconciliation of the Company’s Standardized Measure to PV-10:

	December 31, 2013	2012	2011
	(In millions)		
Standardized Measure of Discounted Net Cash Flows	$4,017.6	$5,840.4	$5,216.3
Present value of future income tax discounted at 10%	1,174.0	1,648.0	1,659.6
PV-10	$5,191.6	$7,488.4	$6,875.9

(4) Standardized Measure represents the present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs, and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions used to calculate PV-10. Standardized Measure differs from PV-10 as Standardized Measure includes the effect of future income taxes.

Proved Reserves - Mid-Continent. Proved reserves in the Mid-Continent, primarily the Mississippian formation, increased from 145.5 MMBoe at December 31, 2011 to 235.8 MMBoe at December 31, 2012 and to 302.3 MMBoe at December 31, 2013, comprising a significant portion of the additions to the Company’s proved reserves in both years. The reserves attributable to producing wells and the continuity of the formation over the development area further support proved undeveloped classification of locations within close proximity to the producing wells. Data from both the Company and operators of offset wells with which it has exchanged technical data demonstrate a consistency in this formation and the fluids in place over an area much larger than the development area. In addition, direct measurement from other producing wells was also used to confirm consistency in reservoir properties such as porosity, thickness and stratigraphic conformity. These wells all encountered proven reserves in the Mississippian formation. The proved undeveloped locations within the development area are generally parallel offsets to the horizontal wells drilled and producing to date.

Proved Reserves - West Texas. In 2013, the Company sold the Permian Properties as discussed in “2013 Divestiture” above. As a result, proved reserves in the Permian Basin decreased by 198.9 MMBoe. During 2012, proved reserves in the Permian Basin, excluding production, increased by 59.5 MMBoe, primarily due to extensions and discoveries associated with successful drilling in the Central Basin Platform, which were slightly offset by downward revisions due mostly to pricing. The Permian Basin provides access to shallow, permeable carbonate reservoirs with decades of production history and predictable production profiles.

Proved Undeveloped Reserves. The following table summarizes activity associated with proved undeveloped reserves during the periods presented:

	Year Ended December 31,		
	2013	2012	2011
Reserves converted from proved undeveloped to proved developed (MMBoe)	44.6	42.6	50.3
Drilling capital expended to convert proved undeveloped reserves to proved developed reserves (in millions)	$437.6	$718.2	$817.0

Excluding asset sales, the Company recognized a net addition to oil, natural gas and NGL reserves associated with proved undeveloped properties of 42 MMBoe for the year ended December 31, 2013. Reserves added from extensions and discoveries totaled 67 MMBoe, primarily from horizontal drilling in the Mississippian formation in the Mid-Continent, which includes 10 MMBoe of proved undeveloped reserves booked and converted during 2013. These additions were offset by downward reserve revisions of 25 MMBoe, primarily from the Mississippian formation, due to the removal of proved undeveloped drilling locations not expected to be drilled within a five year period. These revisions were a result of the Company’s ongoing efforts to optimize its drilling plan within the Mississippian formation and reevaluating anticipated drilling locations. Approximately 35 MMBoe of proved undeveloped reserves at December 31, 2012 were converted to proved developed reserves during 2013.

The Company recognized a net addition to oil, natural gas and NGL reserves associated with proved undeveloped properties, excluding asset sales and purchases of reserves, for the year ended December 31, 2012. Additional reserves attributable to extensions and discoveries, primarily in the Mid-Continent area and Permian Basin area in west Texas, are a result of successful drilling. These additions were partially offset by downward revisions of reserve quantities primarily from the Piñon Field in the WTO as a result of lower natural gas index prices, and, to a lesser extent, downward revisions of reserve quantities due to well performance in the Mid-Continent during 2012. The 12-month average natural gas index price of $4.12 per Mcf for 2011 decreased to $2.76 per Mcf for 2012.

Excluding asset sales, the Company recognized a net addition to oil, natural gas and NGL reserves associated with proved undeveloped properties in 2011. Additional reserves attributable to extensions and discoveries, primarily in the Permian Basin and Mid-Continent areas as a result of successful drilling, more than offset downward revisions of reserve quantities from the Piñon Field in the WTO as a result of lower natural gas index prices. The 12-month average natural gas index price of $4.38 per Mcf for 2010 decreased to $4.12 per Mcf for 2011.

For additional information regarding changes in the Company’s proved reserves during the three years ended December 31, 2013, 2012 and 2011 see “Note 24—Supplemental Information on Oil and Natural Gas Producing Activities” to the Company’s consolidated financial statements in Item 8 of this report.

Significant Fields

Oil, natural gas and NGL production for fields containing more than 15% of the Company's total proved reserves at each year end are presented in the table below. The Mississippi Lime Horizontal, Fuhrman-Mascho and Piñon fields each contained more than 15% of the Company's total proved reserves at December 31, 2013, 2012 or 2011.

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Year Ended December 31, 2013				
Mississippi Lime Horizontal	6,901	1,311	52,618	16,982
Year Ended December 31, 2012				
Mississippi Lime Horizontal	4,536	100	33,034	10,142
Fuhrman-Mascho	4,104	561	1,768	4,960
Year Ended December 31, 2011				
Mississippi Lime Horizontal	1,204	6	8,332	2,598
Fuhrman-Mascho	3,282	487	1,633	4,041
Piñon	41	—	28,246	4,749

Mississippi Lime Horizontal Field. The Mississippi Lime Horizontal Field is located on the Anadarko Shelf in northern Oklahoma and Kansas and produces from the Mississippian formation. The Company's interests in the Mississippi Lime Horizontal Field as of December 31, 2013 included 1,181 gross (730.9 net) producing wells and a 62% average working interest in the producing area.

Fuhrman-Mascho Field. The Fuhrman-Mascho Field is located near the center of the Central Basin Platform in the Permian Basin and produces from the Grayburg-San Andres formation from average depths of approximately 4,500 to 5,000 feet. The Company sold properties located in the Fuhrman-Mascho field and elsewhere in the Permian Basin in February 2013 as discussed in "2013 Divestiture" above.

Piñon Field. The Piñon Field lies along the leading edge of the WTO in Pecos County, Texas. The primary reservoirs are the Tesnus sands (depths ranging from 3,500 to 6,000 feet), the Warwick Caballos chert (depths ranging from 5,000 to 8,000 feet) and the Dugout Creek Caballos chert (depths ranging from 7,000 to 10,000 feet). Low natural gas prices continue to limit development activity in this area.

Production and Price History

The following tables set forth information regarding the Company's net oil, natural gas and NGL production and certain price and cost information for each of the periods indicated.

	Year Ended December 31,		
	2013	2012	2011
Production Data			
Oil (MBbls)	14,279	15,868	9,992
NGL (MBbls)	2,291	2,094	1,838
Natural gas (MMcf)	103,233	93,549	69,306
Total volumes (MBoe)	33,776	33,553	23,381
Average daily total volumes (MBoe/d)	92.5	91.7	64.1
Average Prices(1)			
Oil (per Bbl)	$97.58	$91.79	$90.31
NGL (per Bbl)	$35.16	$33.10	$44.58
Natural gas (per Mcf)	$3.36	$2.49	$3.50
Total (per Boe)	$53.89	$52.43	$52.47

(1) Prices represent actual average prices for the periods presented and do not include effects of derivative transactions.

	Year Ended December 31,		
	2013	2012	2011
Expenses per Boe			
Lease operating expenses			
Transportation	$1.29	$0.89	$0.71
Processing, treating and gathering(1)	1.05	1.18	1.59
Other lease operating expenses(2)	12.60	11.56	10.73
Total lease operating expenses	$14.94	$13.63	$13.03
Production taxes(3)	$0.96	$1.41	$1.97
Ad valorem taxes	$0.35	$0.59	$0.78

(1) Includes costs attributable to gas treatment to remove CO_2 and other impurities from natural gas.

(2) For the years ended December 31, 2013 and 2012, includes $32.7 million and $8.5 million, respectively, for amounts related to the Company's shortfall in meeting its annual CO_2 delivery obligations under a CO_2 treating agreement as described under "—Properties—West Texas" above.

(3) Net of severance tax refunds.

Productive Wells

The following table sets forth the number of productive wells in which the Company owned a working interest at December 31, 2013. Productive wells consist of producing wells and wells capable of producing, including oil wells awaiting connection to production facilities and natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which the Company has a working interest and net wells are the sum of the Company's fractional working interests owned in gross wells.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Area						
Mid-Continent	1,326	805.3	532	233.2	1,858	1,038.5
Gulf of Mexico / Gulf Coast	317	189.3	317	180.7	634	370.0
West Texas	1,009	988.0	887	850.2	1,896	1,838.2
Total	2,652	1,982.6	1,736	1,264.1	4,388	3,246.7

Developed and Undeveloped Acreage

The following table sets forth information regarding the Company's developed and undeveloped acreage at December 31, 2013:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Area				
Mid-Continent	561,878	362,740	2,059,140	1,486,504
Gulf of Mexico / Gulf Coast	640,503	340,146	242,431	153,923
West Texas	52,322	46,775	67,895	48,395
Total	1,254,703	749,661	2,369,466	1,688,822

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage is established prior to such date, in which event the lease will remain in effect until production has ceased. The following table sets forth as of December 31, 2013 the expiration periods of the gross and net acres that are subject to leases in the undeveloped acreage summarized in the above table.

	Acres Expiring	
	Gross	Net
Twelve Months Ending		
December 31, 2014	1,043,631	738,561
December 31, 2015	371,266	275,560
December 31, 2016	491,111	366,521
December 31, 2017 and later	146,974	105,735
Other(1)	316,484	202,445
Total	2,369,466	1,688,822

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(1) Leases remaining in effect until development efforts or production on the developed portion of the particular lease has ceased.

Included in the acreage set to expire during the twelve months ending December 31, 2014, as presented in the table above, are approximately 1,026,000 gross (722,000 net) acres in the Mid-Continent area. The Company has options to extend the leases on a portion of this acreage set to expire in the Mid-Continent in 2014 and expects to exercise such options or hold by production approximately 30% of such acreage based on current drilling and operational plans.

Drilling Activity

The following table sets forth information with respect to wells the Company completed during the periods indicated. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of reserves found. Productive wells are those that produce commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Gross wells refer to the total number of wells in which the Company had a working interest and net wells are the sum of the Company's fractional working interests owned in gross wells. As of December 31, 2013, the Company had 102 gross (78.0 net) operated wells drilling, completing or awaiting completion.

	2013				2012				2011			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Completed Wells												
Development												
Productive	607	98.1 %	482.3	98.1 %	1,054	99.8 %	930.9	99.8 %	895	99.7 %	850.0	99.7 %
Dry	12	1.9 %	9.5	1.9 %	2	0.2 %	1.7	0.2 %	3	0.3 %	2.9	0.3 %
Total	619	100.0 %	491.8	100.0 %	1,056	100.0 %	932.6	100.0 %	898	100.0 %	852.9	100.0 %
Exploratory												
Productive	44	80.0 %	31.0	79.3 %	32	97.0 %	24.3	96.0 %	38	100.0 %	33.7	100.0 %
Dry	11	20.0 %	8.1	20.7 %	1	3.0 %	1.0	4.0 %	—	— %	—	— %
Total	55	100.0 %	39.1	100.0 %	33	100.0 %	25.3	100.0 %	38	100.0 %	33.7	100.0 %
Total												
Productive	651	96.6 %	513.3	96.7 %	1,086	99.7 %	955.2	99.7 %	933	99.7 %	883.7	99.7 %
Dry	23	3.4 %	17.6	3.3 %	3	0.3 %	2.7	0.3 %	3	0.3 %	2.9	0.3 %
Total	674	100.0 %	530.9	100.0 %	1,089	100.0 %	957.9	100.0 %	936	100.0 %	886.6	100.0 %

The following table sets forth information with respect to the rigs operating on the Company's acreage by area as of December 31, 2013.

	Owned	Third-Party	Total
Mid-Continent	8	22	30
Gulf of Mexico / Gulf Coast	—	1	1
West Texas	3	—	3
Total	11	23	34

Marketing and Customers

The Company sells oil, natural gas and NGLs to a variety of customers, including utilities, oil and natural gas companies and trading and energy marketing companies. The Company had three customers that individually accounted for more than 10% of its total revenue during 2013. See "Note 22—Business Segment Information" to the Company's consolidated financial statements in Item 8 of this report for additional information on its major customers. The number of readily available purchasers for the Company's products and the demand for such commodity products makes it unlikely that the loss of a single customer in the areas in which the Company sells its products would materially affect its sales. The Company does not have any material commitments to deliver fixed and determinable quantities of oil and natural gas in the future under existing sales contracts or sales agreements.

Title to Properties

As is customary in the oil and natural gas industry, the Company initially conducts a preliminary review of the title to its properties for which it does not have proved reserves. Prior to the commencement of drilling operations on those properties, the Company conducts a thorough title examination and performs curative work with respect to significant defects. To the extent drilling title opinions or other investigations reflect title defects on those properties, the Company is typically responsible for curing any title defects at its expense. The Company generally will not commence drilling operations on a property until it has cured any material title defects on such property. In addition, prior to completing an acquisition of producing oil and natural gas leases, the Company performs title reviews on the most significant leases, and depending on the materiality of properties, the Company may obtain a drilling title opinion or review previously obtained title opinions. To date, the Company has obtained drilling title opinions on substantially all of its producing properties and believes that it has good and defensible title to its producing properties. The Company's oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens, which the Company believes do not materially interfere with the use of, or affect its carrying value of, the properties.

Drilling and Oil Field Services

Drilling and related oil field services provided by the Company to its exploration and production business and to third parties are described below.

Drilling Operations

The Company drills for its own account in northwestern Oklahoma, Kansas and west Texas through its drilling and oil field services subsidiary. In addition, the Company drills wells for other oil and natural gas companies, primarily in west Texas. The Company believes that drilling with its own rigs allows it to control costs and maintain operating flexibility. The Company's rig fleet is designed to drill in its specific areas of operation and has an average of over 800 horsepower and an average depth capacity of greater than 10,500 feet. As of December 31, 2013, the Company's drilling rig fleet consisted of 27 operational rigs with 11 of these rigs working on Company-owned properties in the

Mid-Continent and west Texas.

The Company obtains its drilling contracts through either competitive bidding or direct negotiations with customers. The Company's drilling contracts generally provide for compensation on a daywork or footage basis. Contract terms offered by the Company generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used, the anticipated duration of the work to be performed and prevailing market rates.

Oil Field Services

The Company's oil field services business conducts operations that, together with its drilling services, complement its exploration and production business. Oil field services include providing pulling units, trucking, rental tools, location and road construction and roustabout services to the Company as well as to third parties.

Customers

During 2013, the Company performed approximately 64% of its drilling and oil field services in support of its exploration and production business. For the years ended December 31, 2013, 2012 and 2011, the Company generated revenues of $66.6 million, $116.6 million and $103.3 million, respectively, for drilling and oil field services performed for third parties.

Capital Expenditures

The Company's capital expenditures for 2013 related to its drilling and oil field services were $7.1 million. The Company has budgeted approximately $15.0 million in capital expenditures in 2014 for its drilling and oil field services segment.

Midstream Services

The Company's midstream services segment primarily provides gathering, compression and treating services of natural gas in west Texas and coordinates the delivery of electricity to the Company's exploration and production operations in the Mississippian formation. The Company's midstream operations and assets serve its exploration and production business as well as other oil and natural gas companies as described below.

Marketing

Through Integra Energy, L.L.C., a wholly owned subsidiary, the Company buys and sells natural gas from wells it operates and wells operated by third parties within its west Texas operations. The Company generally buys and sells natural gas on simultaneous contracts using a portfolio of baseload and spot sales agreements. Identical volumes are bought and sold on monthly and daily contracts using a combination of published pricing indices to eliminate price exposure.

The Company conducts thorough credit checks of all potential purchasers and minimizes its exposure by contracting with multiple parties each month. The Company does not engage in any hedging activities with respect to these contracts. The Company manages several interruptible natural gas transportation agreements in order to take advantage of price differentials or to secure available markets when necessary. The Company currently has 75,000 MMBtu per day of firm transportation service subscribed on the Mid-Continent Express Pipeline through March 2014, which then changes to 50,000 MMBtu per day on Mid-Continent Express Pipeline through March 2019. See "Note 15—Commitments and Contingencies" to the Company's consolidated financial statements in Item 8 of this report for additional information on the contractual fees associated with the firm transportation service.

Mid-Continent

The Company has constructed an electrical transmission system in the Mid-Continent area to coordinate the delivery of electricity to the Company's operations in the area. See discussion of the electrical transmission system under "—Properties—Mid-Continent."

West Texas Gas Treating Plants

The Company owns the Pike’s Peak gas treating plant and the Grey Ranch gas treating plant, both located in Pecos County, Texas, and has a 50% interest in the partnership that leases the Grey Ranch plant from the Company under a lease expiring in 2020. During 2013 and 2012, the Company recorded impairments of $9.9 million and $79.3 million, respectively, on these plants and the Company’s CO_2 compression facilities due to the anticipation that their future use would be limited. Throughout 2012, the Company diverted its high CO_2 natural gas production from its gas treating plants to the Century Plant while it was being tested and commissioned. Upon substantial completion of the Century Plant in late 2012, natural gas volumes delivered by the Company for processing at the Century Plant became subject to the terms of the 30-year treating agreement with Occidental, which contains minimum CO_2 delivery requirements. All natural gas produced in the WTO during 2013 was processed at the Century Plant. See further discussion of the treating agreement under “—Properties—West Texas” above. Due to the continued decline in natural gas production in the WTO resulting from the lack of drilling activity in the area, volumes currently produced in the WTO and delivered to the Century Plant for processing are not sufficient to use all of the available treating capacity at the Century Plant. Due to the sensitivity of drilling activity to market prices for natural gas, drilling activity in the WTO will likely remain very limited if natural gas prices remain low.

The Company is party to a gas gathering agreement and an operations and maintenance agreement with Piñon Gathering Company, LLC ("PGC") related to the Company's properties located in the Piñon Field in west Texas. Under the gas gathering agreement, the Company has dedicated the Piñon Field acreage for priority gathering services for a period of 20 years and will pay a fee for such services. See "Note 15—Commitments and Contingencies" to the Company's consolidated financial statements in Item 8 of this report for additional information on the contractual fees associated with the gas gathering agreement.

Customers

During 2013, the Company performed approximately 64% of its midstream services in support of its exploration and production business. For the years ended December 31, 2013, 2012 and 2011, the Company generated revenues of $56.1 million, $38.8 million and $65.2 million, respectively, from midstream services performed for third parties.

Capital Expenditures

The growth of the Company's midstream assets is driven by its oil and natural gas exploration and production operations. Historically, pipeline and facility expansions are made when warranted by the increase in production or the development of additional acreage. During 2013, the Company spent $55.7 million in capital expenditures primarily to install electrical and compression infrastructure. The Company has budgeted approximately $60.0 million in 2014 capital expenditures for its midstream services segment.

COMPETITION

The Company believes that its leasehold acreage position, drilling and oil field services businesses, midstream assets, geographic concentration of operations, vertical integration and technical and operational capabilities enable it to compete effectively with other exploration and production operations. However, the oil and natural gas industry is intensely competitive, and the Company faces competition in each of its business segments.

The Company competes with major oil and natural gas companies and independent oil and natural gas companies for leases, equipment, personnel and markets for the sale of oil, natural gas and NGLs. Many of these competitors are financially stronger than the Company, but even financially troubled competitors can affect the market because of their need to sell oil, natural gas and NGLs at any price to maintain cash flow. Certain companies may be able to pay more for producing properties and undeveloped acreage. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil, natural gas and NGL prices. The Company's larger or fully integrated competitors may be able to absorb the burden of existing and any future federal, state and local laws and regulations more easily than the Company can, which would adversely affect its competitive position. The Company's ability to acquire additional properties and to discover reserves in the future depends on its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because the Company has fewer financial and human resources than many companies in its industry, the Company may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Oil, natural gas and NGLs compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil, natural gas and NGLs or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil, natural gas and NGLs.

With respect to the Company's drilling business, the Company believes the type, age and condition of its drilling rigs, the quality of its crews and the responsiveness of its management generally enable the Company to compete effectively. However, to the extent the Company drills for third parties, it encounters substantial competition from other drilling contractors. The Company's primary market area is highly competitive. The drilling contracts for which the Company competes are usually awarded on the basis of competitive bids. The Company may, based on the economic environment at the time, determine that market conditions and profit margins are such that contract drilling for third parties is not a beneficial use of its resources.

The Company believes pricing and rig availability are the primary factors its potential customers consider in determining which drilling contractor to select. While the Company must be competitive in its pricing, its competitive strategy generally emphasizes the quality of its equipment and the experience of its rig crews to differentiate it from its competitors. This strategy is less effective when demand for drilling services is weak or there is an oversupply of rigs. These conditions usually result in increased price competition, which makes it more difficult for the Company to compete on the basis of factors other than price. Many of the Company's competitors have greater financial, technical and other resources than the Company does. Their greater capabilities in these areas may enable them to better withstand industry downturns and better retain skilled rig personnel.

The Company believes its geographic concentration of operations enables it to compete effectively in its midstream business. Most of the Company's midstream assets are integrated with its production. However, with respect to third-party natural gas and acquisitions, the Company competes with companies that have greater financial and personnel resources than it does. These companies may have a greater ability to price their services below the Company's prices for similar services.

SEASONAL NATURE OF BUSINESS

Generally, demand for oil and natural gas decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit the Company's drilling and producing activities and other oil and natural gas operations in a portion of its operating areas. These seasonal anomalies can pose challenges for meeting the Company's well drilling objectives, can delay the installation of production facilities, and can increase competition for equipment, supplies and personnel during certain times of the year, which could lead to shortages and increase costs or delay the Company's operations.

ENVIRONMENTAL REGULATIONS

General

The exploration, development and production of oil and natural gas are subject to stringent and comprehensive federal, state, tribal, regional and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection or to employee health and safety. These laws and regulations may, among other things, require permits to conduct drilling, water withdrawal and waste disposal operations; govern the amounts and types of substances that may be disposed or released into the environment; limit or prohibit construction or drilling activities or require formal mitigation measures in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions arising from the Company's operations or attributable to former operations; impose restrictions designed to protect employees from exposure to hazardous substances; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of sanctions, including monetary penalties, the imposition of remedial obligations and the issuance of orders enjoining operations in affected areas. Pursuant to such laws, regulations and permits, the Company may be subject to operational restrictions and has made, and expects to continue to make, capital and other compliance expenditures.

Increasingly, restrictions and limitations are being placed on activities that may affect the environment. Any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly construction, drilling, water management, completion, waste handling, storage, transport, disposal, or remediation requirements or emission or discharge limits could have a material adverse effect on the Company. Moreover, accidental releases or spills may occur in the course of the Company's operations, and there can be no assurance that the Company will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property and natural resources or personal injury.

The following is a summary of the more significant existing environmental and employee, health and safety laws and regulations applicable to the oil and natural gas industry and for which compliance may have a material adverse impact on the Company.

Hazardous Substances and Wastes

The Company currently owns, leases, or operates, and in the past has owned, leased, or operated, properties that have been used to explore for and produce oil and natural gas. The Company believes it has utilized operating and disposal practices that were standard in the industry at the applicable time, but hydrocarbons and wastes may have been disposed or released on or under the properties owned, leased, or operated by the Company or on or under other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes were not under the Company's control. These properties and wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation, and Liability Act, as amended ("CERCLA"), the Resource Conservation and Recovery Act, as amended ("RCRA") and analogous state laws. Under these laws, the Company could be required to remove or remediate previously disposed wastes, to investigate and clean up contaminated property and to perform remedial operations to prevent future contamination or to pay some or all of the costs of any such action.

CERCLA, also known as the Superfund law, and comparable state laws impose joint and several liability without regard to fault or legality of conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances at the site. Under CERCLA, these "responsible persons" may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain environmental and health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury, natural resource damage, and property damage allegedly caused by the release of hazardous substances into the environment. CERCLA also authorizes the Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek recovery from the responsible classes of persons the costs the third parties incur. The Company uses and generates materials in the course of its operations that may be regulated as hazardous substances. To date, no Company-owned or operated site has been designated as a Superfund site, and the Company has not been identified as a responsible party for any Superfund site.

The Company also generates wastes that are subject to the requirements of RCRA and comparable state statutes. RCRA imposes strict requirements on the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Drilling fluids, produced waters and other wastes associated with the exploration, production and/or development of crude oil and natural gas are currently exempt from regulation as hazardous wastes under RCRA. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. In September 2010, the Natural Resources Defense Council filed a petition for rulemaking with the EPA requesting reconsideration of the RCRA exemption for exploration, production, and development wastes. To date, the EPA has not taken any formal action on the petition. Any change in the RCRA exemption for such wastes could result in an increase in costs to manage and dispose of wastes. In the course of the Company's operations, it generates petroleum hydrocarbon wastes and ordinary industrial wastes that are subject to regulation under the RCRA. The Company believes it is in substantial compliance with all regulations regarding the handling and disposal of oil and natural gas wastes from its operations.

Air Emissions

The Clean Air Act, as amended, the Outer Continental Shelf Lands Act (the "OCSLA") and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various permitting, monitoring and reporting requirements. These laws and regulations may require the Company to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of oil and natural gas projects. The Company may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues as a result of such requirements. Additionally, violations of lease conditions or regulations related to air emissions can result in civil and criminal penalties, as well as potential court injunctions curtailing operations and canceling leases. Such enforcement liabilities can result from either governmental or citizen prosecution.

In August 2012, the EPA issued final regulations that established new air emission controls for oil and natural gas production and natural gas processing, including, among other things, new source performance standards for volatile organic compounds that would apply to newly hydraulically fractured wells, existing wells that are re-fractured, compressors, pneumatic controllers, storage vessels and natural gas processing plants placed in service after August 2011. However, in

April 2013, the court granted the EPA's motion for an abeyance until May 30, 2014 of legal challenges to the regulations in order to permit the EPA to reconsider and potentially revise portions of its rules. On September 30, 2013, the EPA filed a status report indicating that it was continuing its reconsideration of the regulations and was in the process of developing revised rules that it planned to propose by April 30, 2014. The EPA has also implemented an engine emission testing program to ensure certain categories of engines, depending on the date manufactured, meet the EPA emission standards. The federal standard for engines manufactured before 2006 also requires emission testing on engines greater than 500 horsepower and strict engine maintenance plans to be in place by October 2013. The Company currently has such maintenance plans in place.

Water Discharges

The Federal Water Pollution Act, as amended (the "Clean Water Act"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to these laws and accompanying regulations, permits must be obtained to discharge produced waters and sand, drilling fluids, drill cuttings and other substances related to the oil and natural gas industry into onshore, coastal and offshore waters of the United States or state waters. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. The Clean Water Act and other laws, such as the OCSLA, require the Company to develop and implement spill response plans intended to prepare the owner of the facility to respond to a hazardous substance or oil discharge. In addition, spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters or adjoining shorelines in the event of a spill, rupture or leak from an onshore, or offshore, facility. The Clean Water Act and analogous state laws also require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The Clean Water Act further imposes certain duties and liabilities on "responsible parties" related to the prevention of oil spills and damages resulting from such spills in, or threatening, United States waters, including the Outer Continental Shelf or adjoining shorelines. A liable responsible party includes the owner or operator of an onshore facility, vessel, or pipeline that is a source, or a potential threat, of an oil discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. The Clean Water Act assigns joint and several strict liability, without regard to fault, to each liable party for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by the Clean Water Act, they are limited. If an oil discharge or substantial threat of discharge were to occur, the Company may be liable for costs and damages, which costs and damages could be material to its results of operations and financial position.

Climate Change

In December 2009, the EPA published its findings that emissions of CO_2, methane and certain other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that restrict emissions of GHGs under existing provisions of the Clean Air Act. Accordingly, the EPA has adopted rules that require a reduction in emissions of GHGs from motor vehicles and also trigger Clean Air Act construction and operating permit review for GHG emissions from certain stationary sources. EPA's endangerment finding and GHG rules were upheld by the United States Court of Appeals for the D.C. Circuit in a June 2012 decision, and a petition for review of the case by the entire D.C. Circuit was denied in December 2012.

The EPA has also adopted rules requiring the reporting of GHG emissions from oil and natural gas production and processing facilities in the United States on an annual basis. The Company believes it has complied with all applicable reporting requirements to date. However, the adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG gases from, the Company's equipment and operations could require it to incur additional costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas it produces. Finally, to the extent increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. Such events could have a material adverse effect on the Company and potentially subject the Company to further regulation.

In addition, Congress has considered legislation to reduce emissions of GHGs and more than one-half of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the adoption of a climate change action plan, completion of GHG emission inventories and/or regional GHG cap and trade programs. Any future federal laws or implemented regulations that may be adopted to address GHG emissions could require the Company to incur increased operating costs, adversely affect demand for the oil and natural gas that the Company produces and have a material adverse effect on the Company's business, financial condition and results of operations.

Endangered Species

The federal Endangered Species Act (the "ESA") restricts activities that may affect endangered or threatened species or their habitats. The Company believes its operations are in substantial compliance with the ESA. If endangered species are located in areas of the underlying properties where the Company wishes to conduct seismic surveys, development activities or abandonment operations, the work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia on September 9, 2011, the U.S. Fish and Wildlife Service is required to consider listing more than 250 species as endangered under the ESA. Under the September 9, 2011 settlement, the federal agency is required to make a determination on listing of the species as endangered or threatened over the six-year period ending with the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause the Company to incur increased costs arising from species protection measures or could result in limitations on its exploration and production activities that could have an adverse impact on its ability to develop and produce reserves. In particular, the Lesser Prairie Chicken, which inhabits portions of Colorado, Kansas, Nebraska, New Mexico, Oklahoma and Texas, is due for a determination on listing as threatened in March of 2014. The impact of a determination for listing the Lesser Prairie Chicken as threatened is unknown at this time. The Company is an active participant on various agency and industry committees that are developing or addressing various EPA and other federal and state agency programs to minimize potential impacts to business activity.

Employee Health and Safety

The Company's operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA Hazardous Communication Standard requires that information be maintained concerning hazardous materials used or produced in the Company's operations and that this information be provided to employees. Pursuant to the Emergency Planning and Community Right-to-Know Act, also known as Title III of the federal Superfund Amendment and Reauthorization Act, businesses that store threshold amounts of chemicals that are subject to OSHA's Hazardous Communication Standard must submit information to state and local authorities in order to facilitate emergency planning and response. That information is generally available to the public. The Company believes that it is in substantial compliance with all applicable laws and regulations relating to worker health and safety.

State Regulation

The states in which the Company operates, along with some municipalities and Native American tribal areas, regulate some or all of the following activities: the drilling for, and the production and gathering of, oil and natural gas, including requirements relating to drilling permits, the location, spacing and density of wells, unitization and pooling of interests, the method of drilling, casing and equipping of wells, the protection of fresh water sources, the orderly development of common sources of supply of oil and natural gas, the operation of wells, allowable rates of production, the use of fresh water in oil and natural gas operations, saltwater injection and disposal operations, the plugging and abandonment of wells and the restoration of surface properties, the prevention of waste of oil and natural gas resources, the protection of the correlative rights of oil and natural gas owners and, where necessary to avoid unfair, unjust or discriminatory service, the fees, terms and conditions for the gathering of natural gas. These regulations may affect the number and location of the Company's wells and the amounts of oil and natural gas that may be produced from the Company’s wells, and increase the costs of the Company’s operations.

Hydraulic Fracturing

Oil and natural gas may be recovered from certain of the Company’s oil and natural gas properties through the use of hydraulic fracturing, combined with sophisticated drilling. Hydraulic fracturing, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices, including the use of diesel, kerosene and similar compounds in the fracturing fluid. In August 2012, the EPA issued final Clean Air Act regulations governing performance standards, including for the capture of air emissions released during hydraulic fracturing. However, in January 2013 the EPA submitted an unopposed motion to the United States Court of Appeals for the D.C. Circuit seeking to stay legal challenges to the Clean Air Act regulations while it reconsiders portions of the new rules. Also, federal legislation previously was introduced, but not enacted, to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In May 2012, the Bureau of Land Management within the U.S. Department of the Interior issued a proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands, but in January 2013 it announced that it would be submitting a revised rule proposal. That revised proposed rule was published for public comment in May 2013. The Department of Interior is now analyzing the comments and is expected to promulgate a final rule sometime in 2014 and 2015.

Certain states in which the Company operates, including Texas, Kansas and Oklahoma, and municipalities therein, have adopted, or are considering adopting, regulations that have imposed, or that could impose, more stringent permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. For example, in February 2012, the Railroad Commission of Texas implemented the Fracturing Disclosure Rule requiring public disclosure of all the chemicals in fluids used in the hydraulic fracturing process. Local ordinances or other regulations may regulate or prohibit the performance of well drilling in general and hydraulic fracturing in particular. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at either the state or federal level, the Company’s fracturing activities could become subject to additional permit requirements, reporting requirements or operational restrictions and also to associated permitting delays and potential increases in costs. These delays or additional costs could adversely affect the determination of whether a well is commercially viable. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce in commercial quantities.

In addition to asserting regulatory authority, a number of federal entities are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In April 2012, President Obama issued an executive order that established a working group for the purpose of coordinating policy, information sharing and planning across federal agencies and offices regarding “unconventional natural gas production,” including hydraulic fracturing. In December 2012, the EPA issued an initial progress report on a study begun in 2011 of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft final report expected to be issued for peer review and comment in late 2014. The EPA has also announced an intent to propose by 2014 effluent limit guidelines that waste water from shale gas extraction operations must meet before going to a treatment plant; the agency also projects that it will publish an Advance Notice of Proposed Rulemaking regarding the Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices, and certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and the U.S. Energy Information Administration to provide a better understanding of that agency’s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. The studies and initiatives described above, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

The Company diligently reviews best practices and industry standards, serves on industry association committees and complies with all regulatory requirements in the protection of potable water sources. Protective practices include, but are not limited to, setting multiple strings of protection pipe across the potable water sources and cementing these pipes from setting depth to surface, continuously monitoring the hydraulic fracturing process in real time and disposing of all non-commercially produced fluids in certified disposal wells at depths below the potable water sources. There have not been any incidents, citations or suits related to the Company’s hydraulic fracturing activities involving environmental concerns.

OTHER REGULATION OF THE OIL AND NATURAL GAS INDUSTRY

The oil and natural gas industry is extensively regulated by numerous federal, state, local, and regional authorities, as well as Native American tribes. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations affecting the oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas industry increases the Company’s cost of doing business and, consequently, affects its profitability, these burdens generally do not affect the Company any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory

Commission (“FERC”). Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC’s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Sales of oil, natural gas and NGLs are not currently regulated and are made at market prices. Although oil, natural gas and NGL prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. The Company cannot predict whether new legislation to regulate oil, natural gas and NGLs might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the Company’s operations.

Drilling and Production

The Company’s operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas where the Company operates also regulate one or more of the following activities:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities;
- the rates of production, or “allowables”;
- the use of surface or subsurface waters;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- the notice to surface owners and other third parties.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce the Company’s interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas the Company can produce from its wells or limit the number of wells or the locations at which the Company can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas, and natural gas liquids within its jurisdiction.

The Oil Conservation Division of the New Mexico Energy, Minerals and Natural Resources Department requires the posting of financial assurance for owners and operators on privately owned or state land within New Mexico in order to provide for abandonment restoration and remediation of wells. The Railroad Commission of Texas imposes financial assurance requirements on operators. The United States Army Corps of Engineers (“ACOE”) and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration.

Natural Gas Sales and Transportation

Historically, federal legislation and regulatory controls have affected the price of the natural gas the Company produces and the manner in which the Company markets its production. FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of the Company’s sales of its own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which the Company may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that the Company produces, as well as the revenues it receives for sales of its natural gas and release of its natural gas pipeline capacity.

Commencing in 1985, FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with an interstate pipeline company. FERC's initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy gas directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, the Company cannot guarantee that the less stringent regulatory approach currently pursued by FERC and Congress will continue indefinitely into the future nor can the Company determine what effect, if any, future regulatory changes might have on the Company's natural gas related activities.

Under FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in-state waters. Although its policy is still in flux, in the past FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase the Company's cost of transporting gas to point-of-sale locations.

EMPLOYEES

As of December 31, 2013, the Company had 1,911 full-time employees, including 276 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of the Company's 1,911 employees, 624 were located at the Company's headquarters in Oklahoma City, Oklahoma at December 31, 2013, and the remaining employees work in the Company's various field offices and drilling sites.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of certain oil and natural gas industry terms used in this report.

2-D seismic or 3-D seismic. Geophysical data that depict the subsurface strata in two dimensions or three dimensions, respectively. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D seismic.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to oil or other liquid hydrocarbons.

Bcf. Billion cubic feet of natural gas.

Boe. Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil. Although an equivalent barrel of condensate or natural gas may be equivalent to a barrel of oil on an energy basis, it is not equivalent on a value basis as there may be a large difference in value between an equivalent barrel and a barrel of oil. For example, based on the commodity prices used to prepare the estimate of the Company’s reserves at year-end 2013 of $93.42/Bbl for oil and $3.67/Mcf for natural gas, the ratio of economic value of oil to gas was approximately 25 to 1, even though the ratio for determining energy equivalency is 6 to 1.

Boe/d. Boe per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

CO_2. Carbon dioxide.

Developed acreage. The number of acres that are assignable to productive wells.

Developed oil, natural gas and NGL reserves. Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill and equip development wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

Development well. A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry well. An exploratory, development or extension well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Environmental Assessment (“EA”). A study to determine whether a federal action significantly affects the environment, which federal agencies may be required by the National Environmental Policy Act or similar state statutes to undertake prior to the commencement of activities that would constitute federal actions, such as oil and natural gas exploration and production activities on federal lands.

Environmental Impact Statement. A more detailed study of the environmental effects of a federal undertaking and its alternatives than an EA, which may be required by the National Environmental Policy Act or similar state statutes, either after the EA has been prepared and determined that the environmental consequences of a proposed federal undertaking, such as oil and natural gas exploration and production activities on federal lands, may be significant, or without the initial preparation of an EA if a federal agency anticipates that a proposed federal undertaking may significantly impact the environment.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to produce oil or natural gas in another reservoir.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geological barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

High CO_2 gas. Natural gas that contains more than 10% CO_2 by volume.

Imbricate stacking. A geological formation characterized by multiple layers lying lapped over each other.

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

MBoe. Thousand barrels of oil equivalent.

Mcf. Thousand cubic feet of natural gas.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMBoe. Million barrels of oil equivalent.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/d. MMcf per day.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

NGL. Natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.

NYMEX. The New York Mercantile Exchange.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

Present value of future net revenues (“PV-10”). The present value of estimated future revenues to be generated from the production of proved reserves, before income taxes, calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation and without giving effect to hedging activities, non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization. PV-10 is calculated using an annual discount rate of 10%.

Production costs.

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Productive well. A well that is found to be capable of producing oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Prospect. A specific geographic area that, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Reserves that are both proved and developed.

Proved oil, natural gas and NGL reserves. Has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which defines proved reserves as:

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 estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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 or gas 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 (including, but not limited to, 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. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
Proved undeveloped reserves. Reserves that are both proved and undeveloped.
Pulling units. Pulling units are used in connection with completions and workover operations.
PV-10. See “Present value of future net revenues” above.
Rental tools. A variety of rental tools and equipment, ranging from trash trailers to blowout preventers to sand separators, for use in the oil field.
Reserves. Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project.
Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).
Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Roustabout services. The provision of manpower to assist in conducting oil field operations.
Standardized measure or standardized measure of discounted future net cash flows. The present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs and future income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes on future net revenues.
Trucking. The provision of trucks to move the Company’s drilling rigs from one well location to another and to deliver water and equipment to the field.
Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.
Undeveloped oil, natural gas and NGL reserves. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations are classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing reasonable certainty.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

Item 1A. Risk Factors

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect the Company’s business, financial condition or results of operations.

The Company’s drilling and operating activities are subject to numerous risks, including the risk that the Company will not discover commercially productive reservoirs. Drilling for oil and natural gas can be unprofitable if dry wells are drilled and if productive wells do not produce sufficient revenues to return a profit. Furthermore, even if sufficient amounts of oil or natural gas exist, the Company may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. Decisions to develop properties depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The estimated cost of drilling, completing and operating wells is uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. In addition, the Company’s drilling and producing operations may be curtailed, delayed or canceled as a result of various factors, including the following:

- delays imposed by or resulting from compliance with regulatory requirements including permitting;
- unusual or unexpected geological formations and miscalculations;
- shortages of or delays in obtaining equipment and qualified personnel;
- shortages of or delays in obtaining water for hydraulic fracturing operations;
- equipment malfunctions, failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- lack of adequate electrical infrastructure and water disposal capacity;
- unexpected operational events and drilling conditions;
- pipe or cement failures and casing collapses;
- pressures, fires, blowouts and explosions;
- lost or damaged drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil, natural gas, brine, water or drilling fluids;
- natural disasters;
- environmental hazards, such as oil and natural gas leaks, pipeline ruptures and discharges of toxic gases or well fluids;
- adverse weather conditions such as extreme cold, fires caused by extreme heat or lack of rain, and severe storms, tornadoes or hurricanes;
- reductions in oil, natural gas and NGL prices;
- oil and natural gas property title problems; and
- market limitations for oil, natural gas and NGLs.

Certain of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, environmental contamination or loss of wells and regulatory fines or penalties.

Oil, natural gas and NGL prices fluctuate due to a number of factors that are beyond the Company’s control, and a decline in oil, natural gas and NGL prices could significantly affect the Company’s financial results and impede its growth.

The Company’s revenues, profitability and cash flow are highly dependent upon the prices it realizes from the sale of oil, natural gas and NGLs. The markets for these commodities are very volatile. Oil, natural gas and NGL prices can fluctuate widely in response to a variety of factors that are beyond the Company’s control. These factors include, among others:

- regional, domestic and foreign supply of, and demand for, oil, natural gas and NGLs, as well as perceptions of supply of, and demand for, oil, natural gas and NGLs;
- the price and quantity of foreign imports;
- U.S. and worldwide political and economic conditions;
- weather conditions and seasonal trends;
- anticipated future prices of oil, natural gas and NGLs, alternative fuels and other commodities;
- technological advances affecting energy consumption and energy supply;
- the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;
- natural disasters and other acts of force majeure;
- domestic and foreign governmental regulations and taxation;
- energy conservation and environmental measures; and
- the price and availability of alternative fuels.

For oil, from January 1, 2010 through December 31, 2013, the highest monthly NYMEX settled price was $113.93 per Bbl and the lowest was $71.92 per Bbl. For natural gas, from January 1, 2010 through December 31, 2013, the highest monthly NYMEX settled price was $5.81 per MMBtu and the lowest was $2.04 per MMBtu. In addition, the market price of oil and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil and natural gas for heating purposes during the winter season.

Lower oil, natural gas and NGL prices may not only decrease the Company’s revenues on a per share basis, but also may ultimately reduce the amount of oil, natural gas and NGLs that it can produce economically and, therefore, could have a material adverse effect on its financial condition and results of operations. This also may cause the Company to make substantial downward adjustments to its estimated proved reserves.

Future price declines may result in reductions of the asset carrying values of the Company’s oil and natural gas properties.

The Company utilizes the full cost method of accounting for costs related to its oil and natural gas properties. Under this accounting method, all costs for both productive and nonproductive properties are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the unit-of-production method. However, the amount of these costs that can be carried as capitalized assets is subject to a ceiling, which limits such pooled costs to the aggregate of the present value of future net revenues of proved oil, natural gas and NGL reserves attributable to proved properties, discounted at 10%, plus the lower of cost or market value of unevaluated properties. The full cost ceiling is evaluated at the end of each quarter using the most recent 12-month average prices for oil and natural gas, adjusted for the impact of derivatives accounted for as cash flow hedges. In the event any of the Company’s derivatives are accounted for as cash flow hedges, the impact of these derivative contracts will be included in the determination of the Company’s full cost ceiling. The Company had no full cost ceiling impairments during the years ended December 31, 2013, 2012 or 2011 and cumulative full cost ceiling limitation impairment charges of $3.5 billion at both December 31, 2013 and 2012. Future declines in oil, natural gas and NGL prices, without other mitigating circumstances, could result in additional losses of future net revenues, including losses attributable to quantities that cannot be economically produced at lower prices, which could cause the Company to record additional write-downs of capitalized costs of its oil and natural gas properties and non-cash charges against future earnings. The amount of such future write-downs and non-cash charges could be substantial.

The Company has a substantial amount of indebtedness and other obligations and commitments, which may adversely affect its cash flow and its ability to operate its business.

As of December 31, 2013, the Company's total indebtedness was $3.2 billion and the Company had preferred stock outstanding with an aggregate liquidation preference of $765.0 million. The Company's substantial level of indebtedness and the dividends associated with its outstanding preferred stock increases the possibility that it may be unable to generate cash sufficient to pay, when due, the principal of, interest on or other amounts due in respect of the Company's indebtedness and/or the preferred stock dividends. The Company's indebtedness and outstanding preferred stock, combined with its lease and other financial obligations and contractual commitments, such as its obligations to drill wells for the Permian Trust and Mississippian Trust II, could have other important consequences to the Company. For example, it could:

- make the Company more vulnerable to adverse changes in general economic, industry and competitive conditions and adverse changes in government regulation;
- require the Company to dedicate a substantial portion of its cash flow from operations to payments on its indebtedness, thereby reducing the availability of the Company's cash flows to fund working capital, capital expenditures, acquisitions and other general corporate purposes;
- limit the Company's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates;
- place the Company at a disadvantage compared to its competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that the Company's indebtedness prevents it from pursuing; and
- limit the Company's ability to borrow additional amounts for working capital, capital expenditures, acquisitions, debt service requirements, execution of its business strategy or other purposes.

Any of the above listed factors could have a material adverse effect on the Company's business, financial condition and results of operations.

The Company's estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of the Company's reserves. The Company's current estimates of reserves could change, potentially in material amounts, in the future.

The process of estimating oil, natural gas and NGL reserves is complex and inherently imprecise, requiring interpretations of available technical data and many assumptions, including assumptions relating to production rates and economic factors such as oil and natural gas prices, drilling and operating expenses, capital expenditures, the assumed effect of governmental regulation and availability of funds for development expenditures. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of the Company's reserves. See "Business—Business Segments and Primary Operations" in Item 1 of this report for information about the Company's oil, natural gas and NGL reserves.

Actual future production, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves will vary and could vary significantly from the Company's estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report, which in turn could have a negative effect on the value of the Company's assets. In addition, from time to time in the future, the Company may adjust estimates of proved reserves, potentially in material amounts, to reflect production history, results of exploration and development, oil, natural gas and NGL prices and other factors, many of which are beyond the Company's control.

The present value of future net cash flows from the Company’s proved reserves calculated in accordance with SEC guidelines will not necessarily be the same as the current market value of its estimated oil, natural gas and NGL reserves.

The Company bases the estimated discounted future net cash flows from its proved reserves on 12-month average prices and costs. Actual future net cash flows from the Company’s oil and natural gas properties will be affected by factors such as:

- actual prices the Company receives for oil, natural gas and NGLs;
- the accuracy of the Company’s reserve estimates;
- the actual cost of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for oil, natural gas and NGLs; and
- changes in governmental regulation or taxation.

The timing of both the Company’s production and its incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the Company uses a 10% discount factor when calculating discounted future net cash flows, which may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and natural gas industry in general.

Unless the Company replaces its oil, natural gas and NGL reserves, its reserves and production will decline, which would adversely affect the Company’s business, financial condition and results of operations.

In February 2014, the Company closed the sale of its Gulf Properties, which accounted for 27% of the Company's total production in the fourth quarter of 2013 and 13% of the Company's reserves at December 31, 2013. In February 2013, the Company closed the sale of its Permian Properties, which accounted for 21% of the Company's total production in the fourth quarter of 2012 and 35% of the Company's reserves at December 31, 2012. The Company's future oil, natural gas and NGL reserves and production, and therefore its cash flow and income, are highly dependent on its success in efficiently developing and exploiting its current reserves and economically finding or acquiring additional recoverable reserves. The Company may not be able to develop, find or acquire additional reserves to replace its current and future production at acceptable costs, which could adversely affect its business, financial condition and results of operations.

The Company will not know conclusively prior to drilling whether oil or natural gas will be present in sufficient quantities to be economically producible.

The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive. The use of seismic data and other technologies and the study of producing fields in the same area do not enable the Company to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. During 2013, the Company completed a total of 674 gross wells, of which 23 were identified as dry wells. If the Company drills additional wells that it identifies as dry wells in its current and future prospects, its drilling success rate may decline and materially harm its business.

Production of oil, natural gas and NGLs could be materially and adversely affected by natural disasters or severe or unseasonable weather.

Production of oil, natural gas and NGLs could be materially and adversely affected by natural disasters or severe weather. Repercussions of natural disasters or severe weather conditions may include:

- evacuation of personnel and curtailment of operations;
- damage to drilling rigs or other facilities, resulting in suspension of operations;
- inability to deliver materials to worksites; and
- damage to, or shutting in of, pipelines and other transportation facilities.

In addition, the Company’s hydraulic fracturing operations require significant quantities of water. Regions in which the Company operates have recently experienced drought conditions. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail the Company’s operations or otherwise result in delays in operations or increased costs.

Volatility in the capital markets could affect the Company’s ability to obtain capital, cause it to incur additional financing expense or affect the value of certain assets.
In recent periods, global financial markets and economic conditions have been volatile due to multiple factors, including significant write-offs in the financial services sector and weak economic conditions. In some cases, the markets have produced downward pressure on stock prices and credit capacity for certain issuers without regard to those issuers’ underlying financial and/or operating strength. Due to this volatility, for many companies the cost of raising money in the debt and equity capital markets has been greater in recent periods than has historically been the case. Continued market volatility may from time to time adversely affect the Company’s ability to access capital and credit markets or to obtain funds at low interest rates or on other advantageous terms. These factors may adversely affect the Company’s business, results of operations or liquidity.

These factors may also adversely affect the value of certain of the Company’s assets and its ability to draw on its senior secured revolving credit facility (“senior credit facility”). Adverse credit and capital market conditions may require the Company to reduce the carrying value of assets associated with derivative contracts to account for non-performance by, or increased credit risk from, counterparties to those contracts. If financial institutions that have extended credit commitments to the Company are adversely affected by volatile conditions of the United States and international capital markets, they may become unable to fund borrowings under their credit commitments to the Company, which could have a material adverse effect on its financial condition and its ability to borrow additional funds, if needed, for working capital, capital expenditures and other corporate purposes.

Properties that the Company buys may not produce as projected, and the Company may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against them.
The Company’s initial technical reviews of properties it acquires are necessarily limited because an in-depth review of every individual property involved in each acquisition generally is not feasible. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well and environmental problems, such as soil or ground water contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the Company may assume certain environmental and other risks and liabilities in connection with acquired properties, and such risks and liabilities could have a material adverse effect on its results of operations and financial condition.

The development of the Company’s proved undeveloped reserves may take longer and may require higher levels of capital expenditures than the Company currently anticipates.
As of December 31, 2013, 36% of the Company’s total reserves were proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than the Company currently anticipates. Therefore, ultimate recoveries from these fields may not match current expectations. Delays in the development of the Company’s reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of the Company’s estimated proved undeveloped reserves and future net revenues estimated for such reserves.

A significant portion of the Company’s operations are located in the Mid-Continent region, making it vulnerable to risks associated with operating in a limited number of major geographic areas.
As of December 31, 2013, approximately 70% of the Company’s proved reserves and approximately 52.7% of its annual production was located in the Mid-Continent. This concentration could disproportionately expose the Company to operational and regulatory risk in these areas. This relative lack of diversification in location of its key operations could expose the Company to adverse developments in these areas or the oil and natural gas markets, including, for example, transportation or treatment capacity constraints, curtailment of production or treatment plant closures for scheduled maintenance. These factors could have a significantly greater impact on the Company’s financial condition, results of operations and cash flows than if the Company’s properties were more diversified.

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The Company’s development and exploration operations require substantial capital, and the Company may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in the Company’s oil, natural gas and NGL reserves.
The oil and natural gas industry is capital intensive. The Company makes substantial capital expenditures in its business and operations for the exploration, development, production and acquisition of oil, natural gas and NGL reserves. Historically, the Company has financed capital expenditures primarily with proceeds from asset sales and from the sale of equity and debt securities and cash generated by operations. In particular, the Company had cash flow from operations of $868.6 million, $783.2 million and $459.0 million, for the years ended December 31, 2013, 2012 and 2011, respectively. The Company expects to finance its future capital expenditures with cash on hand, cash flow from operations, asset sales and available borrowing capacity under its senior credit facility. The Company’s cash flow from operations and access to capital are subject to a number of variables, including:

- the Company’s proved reserves;
- the level of oil, natural gas and NGLs it is able to produce from existing wells;
- the prices at which oil, natural gas and NGLs are sold; and
- the Company’s ability to acquire, locate and produce new reserves.

If the Company’s revenues decrease as a result of lower oil, natural gas and NGL prices, lower production, declines in reserves or for any other reason, the Company may have limited ability to obtain the capital necessary to sustain its operations at current levels. In order to fund the Company’s capital expenditures, it may seek additional financing. However, the Company’s senior credit facility contains covenants limiting its ability to incur additional indebtedness, and the Company’s lenders may withhold their consent to exceed the limitations in such covenants at their sole discretion. The Company’s senior note indentures also contain covenants that may restrict the Company’s ability to incur additional indebtedness if it does not satisfy certain financial metrics. If the Company is unable to obtain additional financing, it may be necessary for the Company to reduce or suspend its capital expenditures.

Disruptions in the global financial and capital markets also could adversely affect the Company’s ability to obtain debt or equity financing on favorable terms, or at all. The failure to obtain additional financing could result in a curtailment of the Company’s operations relating to exploration and development of its prospects, which in turn could lead to a possible loss of properties and a decline in the Company’s oil, natural gas and NGL reserves.

The agreements governing the Company’s existing indebtedness have restrictions, financial covenants and borrowing base redeterminations which could adversely affect its operations.
The Company’s senior credit facility and the indentures governing its senior notes restrict the Company’s ability to, among other things, obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. The senior credit facility also requires the Company to comply with certain financial covenants and ratios. The Company’s ability to comply with these restrictions and covenants in the future is uncertain and could be affected by the levels of cash flow from the Company’s operations and events or circumstances beyond its control. Declining commodity prices could adversely affect the Company’s ability to comply with such restrictions and covenants. The Company’s failure to comply with any of the restrictions and covenants under the senior credit facility, senior notes or other debt financings could result in a default under those instruments, which could cause all of its existing indebtedness to be immediately due and payable.

The Company’s senior credit facility limits the amounts it can borrow to a borrowing base amount. The borrowing base is subject to review semi-annually; however, the lenders reserve the right to have one additional redetermination of the borrowing base per calendar year. Unscheduled redeterminations may be made at the Company’s request, but are limited to two requests per year. Borrowing base determinations are based upon proved developed producing reserves, proved developed non-producing reserves and proved undeveloped reserves. Outstanding borrowings exceeding the borrowing base must be repaid promptly, or the Company must pledge other oil and natural gas properties as additional collateral. The Company may not have the financial resources in the future to make any mandatory principal prepayments under the senior credit facility, which are required, for example, when the committed line of credit is exceeded, proceeds of asset sales in new oil and natural gas properties are not reinvested, or indebtedness that is not permitted by the terms of the senior credit facility is incurred. If the indebtedness under the Company's senior credit facility and senior notes were to be accelerated, the Company's assets may not be sufficient to repay such indebtedness in full.

The Company's derivative activities could result in financial losses and could reduce its earnings.
To achieve a more predictable cash flow and to reduce its exposure to adverse fluctuations in the prices of oil and natural gas, the Company currently has entered, and may in the future enter, into derivative contracts for a portion of its future oil and natural gas production, including fixed price swaps, collars and basis swaps. The Company has not designated and does not plan to designate any of its derivative contracts as hedges for accounting purposes and, as a result, records all derivative contracts on its balance sheet at fair value with changes in the fair value recognized in current period earnings. Accordingly, the Company's earnings may fluctuate significantly as a result of changes in the fair value of its derivative contracts. Derivative contracts also expose the Company to the risk of financial loss in some circumstances, including when:

- production is less than expected;
- the counterparty to the derivative contract defaults on its contract obligations; or
- there is a change in the expected differential between the underlying price in the derivative contract and actual prices received.

In addition, these types of derivative contracts can limit the benefit the Company would receive from increases in the prices for oil and natural gas.

The Company's drilling and services revenues are dependent on the needs of other companies in the oil and natural gas industry.
Companies to which the Company provides drilling and related services are affected by the oil and natural gas industry risks mentioned above. Market prices of oil, natural gas and NGLs, limited access to capital and reductions in capital expenditures could result in oil and natural gas companies canceling or curtailing their drilling programs, which could reduce the demand for the Company's drilling and related services. Any prolonged reduction in the overall level of exploration and development activities, whether resulting from changes in oil, natural gas and NGL prices or otherwise, could impact the Company's drilling and services segment by negatively affecting:

- revenues, cash flow and profitability;
- the Company's ability to retain skilled rig personnel whom it would need in the event of an upturn in the demand for drilling and related services; and
- the fair value of the Company's rig fleet.

Oil and natural gas wells are subject to operational hazards that can cause substantial losses for which the Company may not be adequately insured.
There are a variety of operating risks inherent in oil, natural gas and NGL production and associated activities, such as fires, leaks, explosions, mechanical problems, major equipment failures, blowouts, uncontrollable flow of oil, natural gas and NGLs, water or drilling fluids, casing collapses, abnormally pressurized formations and natural disasters. The occurrence of any of these or similar accidents that temporarily or permanently halt the production and sale of oil, natural gas and NGLs at any of the Company's properties could have a material adverse impact on its business activities, financial condition and results of operations.

Additionally, if any of such risks or similar accidents occur, the Company could incur substantial losses as a result of injury or loss of life, severe damage or destruction of property, natural resources and equipment, regulatory investigation and penalties and environmental damage and clean-up responsibility. If the Company experiences any of these problems, its ability to conduct operations could be adversely affected. While the Company maintains insurance coverage that it deems appropriate for these risks, its operations may result in liabilities exceeding such insurance coverage or liabilities not covered by insurance.

Shortages or increases in costs of equipment, services and qualified personnel could adversely affect the Company's ability to execute its exploration and development plans on a timely basis and within its budget.

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Additionally, higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly affect the Company’s ability to execute its exploration and development plans as projected.

Market conditions or operational impediments may hinder the Company's access to oil, natural gas and NGL markets or delay production of oil, natural gas and NGLs.
Market conditions or a lack of satisfactory oil and natural gas transportation arrangements may hinder the Company's access to oil, natural gas and NGL markets or delay production of oil, natural gas and NGLs. The availability of a ready market for the Company's oil, natural gas and NGL production depends on a number of factors, including the demand for and supply of oil, natural gas and NGLs and the proximity of reserves to pipelines and terminal facilities. The Company's ability to market its production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and treating facilities. The Company's failure to obtain such services on acceptable terms in the future or to expand its midstream assets could have a material adverse effect on its business. The Company may be required to shut in wells for a lack of a market or because access to natural gas pipelines, gathering system capacity or treating facilities may be limited or unavailable. The Company would be unable to realize revenue from any shut-in wells until production arrangements were made to deliver the production to market.

Competition in the oil and natural gas industry is intense, which may adversely affect the Company's ability to succeed.
The oil and natural gas industry is intensely competitive, and the Company competes with many companies that have greater resources than it does. Many of these companies not only explore for and produce oil and natural gas, but also conduct refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than the Company's financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. The Company's larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than it can, which would adversely affect its competitive position. The Company's ability to acquire additional properties and to identify reserves in the future will depend upon its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because the Company has fewer financial and human resources than many companies in its industry, it may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

Downturns in oil and natural gas prices can result in decreased oil field activity which, in turn, can result in an oversupply of service providers and drilling rigs. This oversupply can result in severe reductions in prices received for oil field services or a complete lack of work for crews and equipment.

The Company's use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas. In addition, the use of such technology requires greater predrilling expenditures, which could adversely affect the results of the Company's drilling operations.
A significant aspect of the Company's exploration and development plan involves seismic data. Even when properly used and interpreted, 2-D and 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are present in those structures. Other geologists and petroleum professionals, when studying the same seismic data, may have significantly different interpretations than the Company's professionals.

In addition, the use of 2-D and 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and the Company could incur losses due to such expenditures. As a result, the Company's drilling activities may not be geologically successful or economical, and its overall drilling success rate or its drilling success rate for activities in a particular area may not improve.

The Company may often gather 2-D and 3-D seismic data over large areas. The Company's interpretation of seismic data delineates for it those portions of an area that it believes are desirable for drilling. Therefore, the Company may choose not to acquire option or lease rights prior to acquiring seismic data, and in many cases, the Company may identify hydrocarbon indicators before seeking option or lease rights in the location. If the Company is not able to lease those locations on acceptable terms, it will have made substantial expenditures to acquire and analyze 2-D and 3-D seismic data without having an opportunity to attempt to benefit from those expenditures.

Many of the Company's prospects in the WTO may contain natural gas that is high in CO_2 content, which can negatively affect its economics.
The reservoirs of many of the Company's prospects in the WTO may contain natural gas that is high in CO_2 content. The natural gas produced from these reservoirs must be treated for the removal of CO_2 prior to marketing. If the Company cannot obtain sufficient capacity at treatment facilities for its natural gas with a high CO_2 concentration, or if the cost to obtain such capacity significantly increases, the Company could be forced to delay production and development or experience increased production costs. The Company sometimes encounters CO_2 levels in its wells that are higher than expected. Since the treatment expenses are incurred on a per Mcf basis, the Company will incur a higher effective treating cost per MMBtu of natural gas sold for natural gas with a higher CO_2 content. As a result, high CO_2 gas wells must produce at much higher rates than low CO_2 gas wells to be economic, especially in a low natural gas price environment.

Furthermore, when the Company treats the gas for the removal of CO_2, some of the methane is used to run the treatment plant as fuel gas and other methane and heavier hydrocarbons, such as ethane, propane and butane, cannot be separated from the CO_2 and is lost. This is known as plant shrink. During 2013, the Company's plant shrink has been approximately 6% in the WTO. After giving effect to plant shrink, typically 3.1 Mcf of high CO_2 natural gas must be produced to sell one MMBtu of natural gas. The Company reports its volumes of natural gas reserves and production net of CO_2 volumes that are removed prior to sales.

Low levels of natural gas production in the WTO, due to declines in production from existing wells, depressed commodity prices or otherwise, currently adversely affect, and could in the future adversely affect, the Company's ability to satisfy certain contractual obligations and revenues and cash flow from its midstream services segment.
The Company has entered into long-term gas gathering agreements with each of PGC and Occidental. These agreements require the Company to annually deliver certain minimum volumes of natural gas to PGC through June 30, 2029 and CO_2 to Occidental through December 31, 2042 and to compensate PGC and Occidental to the extent it does not satisfy the contractual delivery requirements. Decreased production in the WTO, where the applicable natural gas assets are located, has resulted in, and may continue to result in, a decline in the volume of natural gas and CO_2 delivered to PGC and Occidental, respectively, and to its own pipelines and facilities for gathering, transporting and treating. The Company has no control over many factors affecting production activity in the WTO, including prevailing and projected natural gas prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital. As a consequence of these factors, the Company has not produced and delivered, and may continue to not produce and deliver, sufficient quantities of natural gas or CO_2 to meet its contractual delivery obligations to PGC and Occidental. The Company is required to compensate PGC and Occidental for shortfalls in its contractual delivery obligations. The Company accrued $32.7 million at December 31, 2013 for its 2013 shortfalls under its contract with Occidental and expects to accrue between approximately $30.0 million and $37.0 million during the year ending December 31, 2014 for amounts related to the Company's anticipated shortfall in meeting its 2014 annual delivery obligations to Occidental based on current projected natural gas production levels. In future years, amounts payable to PGC and/or Occidental for such shortfalls could be material. In addition, if the Company fails to connect new wells to its gathering systems, the amount of natural gas it gathers, transports and treats will decline substantially over time and could, upon exhaustion of the current wells, cause the Company to abandon its gathering systems and, possibly cease gathering, transporting and treating operations.

The Company is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting its operations or expose it to significant liabilities.
The Company's oil and natural gas exploration, production, transportation and treatment operations are subject to complex and stringent laws and regulations. In order to conduct its operations in compliance with these laws and regulations, the Company must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. The Company may incur substantial costs in order to maintain compliance with these laws and regulations. As well as recent incidents involving the release of oil and natural gas and fluids as a

result of drilling activities in the United States, there have been a variety of regulatory initiatives at the federal and state levels to restrict oil and natural gas drilling operations in certain locations. Any increased regulation or suspension of oil and natural gas exploration and production, or revision or reinterpretation of existing laws and regulations, that arises out of these incidents or otherwise could result in delays and higher operating costs. Such costs or significant delays could have a material adverse effect on the Company's business, financial condition and results of operations. The Company must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent the Company is a shipper on interstate pipelines, it must comply with the tariffs of such pipelines and with federal policies related to the use of interstate capacity.

Laws and regulations governing oil and natural gas exploration and production may also affect production levels. The Company is required to comply with federal and state laws and regulations governing conservation matters, including provisions related to the unitization or pooling of the oil and natural gas properties; the establishment of maximum rates of production from wells; the spacing of wells; and the plugging and abandonment of wells. These and other laws and regulations can limit the amount of oil and natural gas the Company can produce from its wells, limit the number of wells it can drill, or limit the locations at which it can conduct drilling operations.

New laws or regulations, or changes to existing laws or regulations, may unfavorably impact the Company, could result in increased operating costs and could have a material adverse effect on the Company’s financial condition and results of operations. For example, Congress has recently considered, and may continue to consider, legislation that, if adopted in its proposed form, would subject companies involved in oil and natural gas exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, and the elimination of certain U.S. federal tax preferences available with respect to oil and natural gas exploration and production activities. In addition, the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) and rules promulgated thereunder could reduce trading positions in the energy futures or swaps markets and materially reduce hedging opportunities for the Company, which could adversely affect its revenues and cash flows during periods of low commodity prices, and which could adversely affect the Company’s ability to restructure its hedges when it might be desirable to do so.

Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may increase capital costs for the Company and third-party downstream oil and natural gas transporters. These and other potential regulations could increase the Company’s operating costs, reduce its liquidity, delay its operations, increase direct and third-party post production costs or otherwise alter the way the Company conducts its business, which could have a material adverse effect on its financial condition, results of operations and cash flows and which could reduce cash received by or available for distribution, including any amounts paid by the Company for transportation on downstream interstate pipelines.

The Company’s operations are subject to environmental laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations or result in significant costs and liabilities.
The Company’s oil and natural gas exploration and production operations are subject to stringent and comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to operations, including the acquisition of a permit before conducting drilling; water withdrawal or waste disposal activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the imposition of regulations designed to protect employees from exposure to hazardous substances; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Failure to comply with these laws and regulations may result in litigation; the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of the Company’s operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of the Company’s operations due to its handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to its operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, the Company could be subject to joint and several strict liability for the investigation, removal or remediation of previously released materials or property contamination regardless of whether it was responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which the Company’s wells are drilled and facilities where its petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for contamination even in the absence of non-compliance, with environmental laws and regulations or for personal injury, natural resources damage or property damage.

In addition, the risk of accidental spills or releases could expose the Company to significant liabilities that could have a material adverse effect on the Company’s financial condition or results of operations. Certain laws related to oil spills impose joint and several strict liability, without regard to fault, for all containment and oil removal costs and a variety of public and private damages including, but not limited to, the costs of responding to a release of oil, natural resource damages, and economic damages suffered by persons adversely affected by an oil spill. Although defenses exist to the liability imposed by those laws, they are limited. If an oil discharge or substantial threat of discharge were to occur, the Company may be liable for costs and damages, which costs and damages could be material to its results of operations and financial position.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly construction, drilling, water management, completion, waste handling, storage, transport, disposal or cleanup requirements could require significant expenditures by the Company to attain and maintain compliance and may otherwise have a material adverse effect on its results of operations, competitive position or financial condition. The Company may not be able to recover some or any of these costs from insurance. As a result of any increased cost of compliance, the Company may decide to discontinue drilling.

Federal and state legislative and regulatory initiatives as well as governmental reviews relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect the Company's level of production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations, such as shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing is typically regulated by state oil and gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices, including the use of diesel, kerosene and similar compounds in fracturing fluid. In August 2012, the EPA issued final Clean Air Act regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing. However, in January 2013 the EPA submitted an unopposed motion to the United States Court of Appeals for the D.C. Circuit seeking to stay legal challenges to the Clean Air Act regulations while the EPA reconsiders portions of the new rules. Also, legislation has been introduced, but not enacted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In May 2012, the Bureau of Land Management within the U.S. Department of the Interior issued a proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands, but in January 2013 it announced that it would be submitting a revised proposed rule. That revised proposed rule was published for public comment in May 2013. The Department of Interior is now analyzing the comments and is expected to promulgate a final rule sometime in 2014 or 2015.

Certain states in which the Company operates, including Texas, Kansas and Oklahoma, and municipalities have adopted, or are considering adopting, regulations that have imposed, or that could impose, more stringent permitting, disclosure, disposal and well construction requirements on hydraulic fracturing operations. For example, in February 2012, the Railroad Commission of Texas implemented the Fracturing Disclosure Rule, requiring public disclosure of all the chemicals in fluids used in the hydraulic fracturing process. Local ordinances or other regulations may regulate or prohibit the performance of well drilling in general and hydraulic fracturing in particular. If new laws or regulations that significantly restrict or regulate hydraulic fracturing are adopted at either the state or the federal level, the Company's fracturing activities could become subject to additional permit requirements, reporting requirements or operational restrictions and also to associated permitting delays, or additional costs could adversely affect the determination of whether a well is commercially viable. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce in commercial quantities.

In addition to asserting regulatory authority, a number of federal entities are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. In April 2012, President Obama issued an executive order that established a working group for the purpose of coordinating policy, information sharing, and planning among federal agencies and offices regarding "unconventional natural gas production," including hydraulic fracturing. In December 2012, the EPA issued an initial progress report on a study begun in 2011 of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft final report expected to be issued for peer review and comment in late 2014. The EPA has also announced its intent to propose by 2014 effluent limit guidelines that waste water from shale gas extraction operations must meet before going to a treatment plant; the agency also projects that it will publish an Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Additionally, a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices, and certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources; the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing; and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. Bills previously have been introduced in both the Senate and the House of Representatives to, among other things, amend the federal Safe Drinking Water Act to repeal provisions that currently exempt hydraulic fracturing operations from restrictions that otherwise would apply to underground injection of fluids or propping agents. The studies and initiatives described above, depending on their degree of pursuit and any meaningful results obtained, could spur efforts to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Climate change laws and regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the oil and natural gas that the Company produces while the physical effects of climate change could disrupt the Company’s production and cause the Company to incur significant costs in preparing for or responding to those effects.
In December 2009, the EPA published its findings that emissions of GHGs present a danger to public health and the environment because such gases are contributing to warming of the Earth’s atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the Clean Air Act. Accordingly, the EPA has adopted rules that require a reduction in emissions of GHGs from motor vehicles and also trigger Clean Air Act construction and operating permit review for GHG emissions from certain stationary sources. The EPA’s endangerment finding and GHG rules were upheld by the United States Court of Appeals for the D.C. Circuit in a June 2012 decision, and a petition for review of the case by the entire D.C. Circuit was denied in December 2012.

The EPA also has adopted rules requiring the reporting of GHG emissions from oil and natural gas production and processing facilities in the United States on an annual basis. The Company believes it has complied with all applicable reporting requirements to date. However, the adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, the Company’s equipment and operations could require it to incur additional costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil and natural gas that it produces. Finally, to the extent increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that could have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events, such events could have a material adverse effect on the Company’s assets and operations, and potentially subject the Company to greater regulation.

In addition, Congress has considered legislation to reduce emissions of GHGs and more than half of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the adoption of a climate change action plan, completion of GHG emission inventories and/or regional GHG cap and trade programs. Any future federal laws or implemented regulations that may be adopted to address GHG emissions could require the Company to incur increased operating costs, adversely affect demand for the oil and natural gas that the Company produces and have a material adverse effect on the Company’s business, financial condition and results of operations.

Repercussions from terrorist activities or armed conflict could harm the Company’s business.
Terrorist activities, anti-terrorist efforts or other armed conflict involving the United States or its interests abroad may adversely affect the United States and global economies and could prevent the Company from meeting its financial and other obligations. If events of this nature occur and persist, the attendant political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on prevailing oil and natural gas prices and causing a reduction in the Company’s revenues. Oil and natural gas production facilities, transportation systems and storage facilities could be direct targets of terrorist attacks, and/or operations could be adversely impacted if infrastructure integral to the Company’s operations is destroyed by such an attack. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

If the Company fails to maintain an adequate system of internal control over financial reporting, it could adversely affect its ability to accurately report its results.
Management is responsible for establishing and maintaining adequate internal control over financial reporting. The Company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with generally accepted accounting principles. A material weakness is a deficiency, or a combination of deficiencies, in the Company’s internal control over financial reporting that results in a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. Effective internal controls are

necessary for the Company to provide reliable financial reports and deter and detect any material fraud. If the Company cannot provide reliable financial reports or prevent material fraud, its reputation and operating results would be harmed. The Company’s efforts to develop and maintain its internal controls may not be successful, and it may be unable to maintain adequate controls over its financial processes and reporting in the future, including future compliance with the obligations under Section 404 of the Sarbanes-Oxley Act of 2002. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation, including those related to acquired businesses, or other effective improvement of the Company’s internal controls could harm its operating results. Ineffective internal controls could also cause investors to lose confidence in the Company’s reported financial information.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation.

The Obama administration's budget proposals in recent years, including the budget proposal for fiscal year 2014, have included provisions eliminating certain key U.S. federal income tax preferences currently available to companies involved in oil and gas exploration and production. If enacted into law, these provisions would repeal certain incentives and credits applicable to taxpayers engaged in the exploration or production of natural resources. These provisions include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the repeal of current expensing of intangible drilling and development costs, (iii) the repeal of domestic manufacturing deduction for oil and natural gas production and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for, or development of, oil and gas within the United States. It is unclear whether any similar provisions will be included in future budget proposals, whether such provisions will actually be enacted or how soon any such provisions would become effective if enacted. The passage of any legislation relating to such proposals or any other similar changes in U.S. federal income tax laws could negatively affect the Company's financial condition and results of operations.

New derivatives legislation and regulation could adversely affect the Company's ability to hedge risks associated with its business.

The Dodd-Frank Act created a new regulatory framework for oversight of derivatives transactions by the Commodity Futures Trading Commission (the "CFTC") and the SEC. Among other things, the Dodd-Frank Act subjects certain swap participants to new capital, margin and business conduct standards. In addition, the Dodd-Frank Act contemplates that where appropriate in light of outstanding exposures, trading liquidity and other factors, swaps (broadly defined to include most hedging instruments other than futures) will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. The Dodd-Frank Act also established a new Energy and Environmental Markets Advisory Committee to make recommendations to the CFTC regarding matters of concern to exchanges, firms, end users and regulators with respect to energy and environmental markets and also expands the CFTC's power to impose position limits on specific categories of swaps (excluding swaps entered into for bona fide hedging purposes).

There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. However, although the Company may qualify for exceptions, its derivatives counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the Dodd-Frank Act, which may increase the Company's transaction costs or make it more difficult for the Company to enter into hedging transactions on favorable terms. The Company's inability to enter into hedging transactions on favorable terms, or at all, could increase its operating expenses and put it at increased exposure to risks of adverse changes in oil and natural gas prices, which could adversely affect the predictability of cash flows from sales of oil and natural gas.

In November 2011, the CFTC finalized rules to establish a position limits regime on certain "core" physical-delivery contracts and their economically equivalent derivatives, some of which reference major energy commodities, including oil and natural gas. However, in September 2012, the District Court of the District of Columbia vacated the CFTC's rulemaking and remanded to the CFTC for further proceedings. On November 6, 2013, the CFTC re-proposed rules to establish a position limits regime on 28 "core" physical commodity contracts and their "economically equivalent" futures, options, and swaps, some of which reference major energy commodities, including oil and natural gas ("Position Limits Re-Proposal"). The comment period for the Position Limits Re-Proposal closed on February 10, 2014, but the final rules related to position limits are not yet in effect. To the extent the Position Limits Re-Proposal is finalized, such regulations could subject the Company or its derivatives counterparties to limits on commodity positions and thereby have an adverse effect on its ability to hedge risks associated with its business or on the cost of its hedging activity.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding the Company’s properties is included in Item 1.

Item 3. Legal Proceedings

On April 5, 2011, Wesley West Minerals, Ltd. and Longfellow Ranch Partners, LP filed suit against the Company and SandRidge Exploration and Production, LLC (collectively, the “SandRidge Entities”) in the 83rd District Court of Pecos County, Texas. The plaintiffs, who have leased mineral rights to the SandRidge Entities in Pecos County, allege that the SandRidge Entities have not properly paid royalties on all volumes of natural gas and CO_2 produced from the acreage leased from the plaintiffs. The plaintiffs also allege that the SandRidge Entities have inappropriately failed to pay royalties on CO_2 produced from the plaintiffs’ acreage that results from the treatment of natural gas at the Century Plant. The plaintiffs seek approximately $45.5 million in actual damages for the period of time between January 2004 and December 2011, punitive damages and a declaration that the SandRidge Entities must pay royalties on CO_2 produced from the plaintiffs’ acreage that results from treatment of natural gas at the Century Plant. The Commissioner of the General Land Office of the State of Texas (“GLO”) is named as an additional defendant in the lawsuit as some of the affected oil and natural gas leases described in the plaintiffs’ allegations cover mineral classified lands in which the GLO is entitled to one-half of the royalties attributable to such leases. The GLO has filed a cross-claim against the SandRidge Entities asserting the same claims as the plaintiffs with respect to the leases covering mineral classified lands and seeking approximately $13.0 million in actual damages, inclusive of penalties and interest. On February 5, 2013, the Company received a favorable summary judgment ruling that effectively removes a majority of the plaintiffs’ and GLO’s claims. On April 29, 2013, the court entered an order allowing for an interlocutory appeal of its summary judgment ruling. The Company intends to continue to defend the remaining issues in this lawsuit as well as any appellate proceedings. At the time of the ruling on summary judgment, the lawsuit was still in the discovery stage and, accordingly, an estimate of reasonably possible losses associated with the remaining causes of action, if any, cannot be made until all of the facts, circumstances and legal theories relating to such claims and the SandRidge Entities’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

On August 4, 2011, Patriot Exploration, LLC, Jonathan Feldman, Redwing Drilling Partners, Mapleleaf Drilling Partners, Avalanche Drilling Partners, Penguin Drilling Partners and Gramax Insurance Company Ltd. filed a lawsuit against the Company, SandRidge Exploration and Production, LLC (“SandRidge E&P”) and certain current and former directors and senior executive officers of the Company (collectively, the “defendants”) in the U.S. District Court for the District of Connecticut. On October 28, 2011, the plaintiffs filed an amended complaint alleging substantially the same allegations as those contained in the original complaint. The plaintiffs allege that the defendants made false and misleading statements to U.S. Drilling Capital Management LLC and to the plaintiffs prior to the entry into a participation agreement among Patriot Exploration, LLC, U.S. Drilling Capital Management LLC and SandRidge E&P, which provided for the investment by the plaintiffs in certain of SandRidge E&P’s oil and natural gas properties. To date, the plaintiffs have invested approximately $16.0 million under the participation agreement. The plaintiffs seek compensatory and punitive damages and rescission of the participation agreement. On November 28, 2011, the defendants filed a motion to dismiss the amended complaint. On June 29, 2013, the court granted in part and denied in part the defendants’ motion. The Company and the other defendants intend to defend this lawsuit vigorously and believe the plaintiffs’ claims are without merit. This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

Between December 2012 and March 2013, seven putative shareholder derivative actions were filed in state and federal court in Oklahoma:

- Arthur I. Levine v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on December 19, 2012 in the U.S. District Court for the Western District of Oklahoma
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- Deborah Depuy v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on January 22, 2013 in the U.S. District Court for the Western District of Oklahoma
- Paul Elliot, on Behalf of the Paul Elliot IRA R/O, v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on January 29, 2013 in the U.S. District Court for the Western District of Oklahoma
- Dale Hefner v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on January 4, 2013 in the District Court of Oklahoma County, Oklahoma
- Rocky Romano v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on January 22, 2013 in the District Court of Oklahoma County, Oklahoma
- Joan Brothers v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on February 15, 2013 in the U.S. District Court for the Western District of Oklahoma
- Lisa Ezell, Jefferson L. Mangus, and Tyler D. Mangus v. Tom L. Ward, et al., and SandRidge Energy, Inc., Nominal Defendant - filed on March 22, 2013 in the U.S. District Court for the Western District of Oklahoma

Each lawsuit identified above was filed derivatively on behalf of the Company and names as defendants current and former directors of the Company. The Hefner lawsuit also names as defendants certain current and former senior executive officers of the Company. All seven lawsuits assert overlapping claims - generally that the defendants breached their fiduciary duties, mismanaged the Company, wasted corporate assets, and engaged in, facilitated or approved self-dealing transactions in breach of their fiduciary obligations. The Depuy lawsuit also alleges violations of federal securities laws in connection with the Company allegedly filing and distributing certain misleading proxy statements. The lawsuits seek, among other relief, injunctive relief related to the Company’s corporate governance and unspecified damages.

On April 10, 2013, the U.S. District Court for the Western District of Oklahoma consolidated the Levine, Depuy, Elliot, Brothers, and Ezell actions (the “Federal Shareholder Derivative Litigation”) under the caption “In re SandRidge Energy, Inc. Shareholder Derivative Litigation,” appointed a lead plaintiff and lead counsel, and ordered the lead plaintiff to file a consolidated complaint by May 1, 2013. On June 3, 2013, the Company and the individual defendants filed their respective motions to dismiss the consolidated complaint. On September 11, 2013, the court granted the defendants’ respective motions to dismiss the consolidated complaint without prejudice, and granted plaintiffs leave to file an amended consolidated complaint. The plaintiffs filed an amended consolidated complaint on October 9, 2013, in which plaintiffs allege that: (i) the Company’s former CEO, Tom Ward, breached his fiduciary duties by usurping corporate opportunities, (ii) certain of the Company’s current and former directors breached their fiduciary duties of care, (iii) Mr. Ward and certain of the Company’s current and former directors wasted corporate assets, (iv) certain entities allegedly affiliated with Mr. Ward aided and abetted Mr. Ward’s breaches of fiduciary duties, (v) Mr. Ward and entities allegedly affiliated with Mr. Ward misappropriated the Company’s confidential and proprietary information, and (vi) entities allegedly affiliated with Mr. Ward were unjustly enriched. The defendants have filed respective motions to dismiss the amended consolidated complaint, which are pending before the court.

The Company and the individual defendants in the Hefner and Romano actions (the “State Shareholder Derivative Litigation”) moved to stay each of the actions in favor of the Federal Shareholder Derivative Litigation, in order to avoid duplicative proceedings, and also requested, in the alternative, the dismissal of the State Shareholder Derivative Litigation.

On June 19, 2013, the court stayed the Hefner action until at least November 29, 2013. The court subsequently lifted its stay for purposes of hearing and deciding the defendants’ respective motions to dismiss. On September 18, 2013, the court denied the defendants’ motions to dismiss.

On May 8, 2013, the court stayed the Romano action pending further order of the court. On October 31, 2013, the plaintiff filed a motion to lift the stay, which was denied by the court on February 7, 2014.

Because the Federal Shareholder Derivative Litigation and the State Shareholder Derivative Litigation are in the early stages, an estimate of reasonably possible losses associated with each of them, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs’ claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to these actions.

On December 5, 2012, James Glitz and Rodger A. Thornberry, on behalf of themselves and all other similarly situated stockholders, filed a putative class action complaint in the U.S. District Court for the Western District of Oklahoma against SandRidge Energy, Inc. and certain current and former executive officers of the Company. On January 4, 2013, Louis Carbone, on behalf of himself and all other similarly situated stockholders, filed a substantially similar putative class action complaint in the same court and against the same defendants. On March 6, 2013, the court consolidated these two actions under the caption “In re SandRidge Energy, Inc. Securities Litigation” (the “Securities Litigation”) and appointed a lead plaintiff and lead counsel. On July 23, 2013, plaintiffs filed a consolidated amended complaint, which asserts a variety of federal securities claims against the Company and certain of its current and former officers and directors, among other defendants, on behalf of a putative class of (a) purchasers of SandRidge common stock during the period from February 24, 2011 to November 8, 2012, (b) purchasers of common units of the Mississippian Trust I in or traceable to its initial public offering on or about April 12, 2011, and (c) purchasers of common units of the Mississippian Trust II (together with the Mississippian Trust I, the "Mississippian Trusts") in or traceable to its initial public offering on or about April 23, 2012. The claims are based on allegations that the Company, certain of its current and former officers and directors, and the Mississippian Trusts, among other defendants, are responsible for making false and misleading statements, and omitting material information, concerning a variety of subjects, including oil and natural gas reserves, the Company's capital expenditures, and certain transactions entered into by companies allegedly affiliated with the Company's former Chief Executive Officer ("CEO") Tom Ward. The defendants have filed respective motions to dismiss the consolidated amended complaint, which are pending before the court. Because the Securities Litigation is in the early stages, an estimate of reasonably possible losses associated with it, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the defendants' defenses are fully disclosed and analyzed. The Company has not established any reserves relating to the Securities Litigation. Each of the Mississippian Trusts has requested that the Company indemnify it for any losses it may incur in connection with the Securities Litigation.

On July 15, 2013, James Hart and fifteen other named plaintiffs filed an amended complaint in the United States District Court for the District of Kansas in an action undertaken individually and on behalf of others similarly situated against SandRidge Energy, Inc., SandRidge Operating Company, SandRidge E&P, SandRidge Midstream, Inc., and Lariat Services, Inc. In their amended complaint, plaintiffs allege that the defendants failed to properly calculate overtime pay for the plaintiffs and for other similarly situated current and former employees. The plaintiffs further allege that the defendants required the plaintiffs and other similarly situated current and former employees to engage in work-related activities without pay. The plaintiffs assert claims against the defendants for (i) violations of the Fair Labor Standards Act, (ii) violations of the Kansas Wage Payment Act, (iii) breach of contract, and (iv) fraud, and seek to recover unpaid wages and overtime pay, liquidated damages, statutory penalties, economic damages, compensatory and punitive damages, attorneys’ fees and costs, and both pre- and post-judgment interest.

On October 3, 2013, the plaintiffs filed a Motion for Conditional Collective Action Certification and for Judicial Notice to Class and a Motion to Toll the Statute of Limitations. On October 11, 2013, the defendants filed a Motion to Dismiss and a Motion to Transfer Venue to the United States District Court for the Western District of Oklahoma. All of these motions are pending before the court. The Company and the other defendants intend to defend this lawsuit vigorously. This lawsuit is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this action, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs’ claims and the defendants’ defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

On December 18, 2013, the Company received a subpoena duces tecum from the U.S. Department of Justice in connection with an ongoing investigation of possible violations of antitrust laws in connection with the purchase or lease of land, oil or natural gas rights. The Company is cooperating with the investigation.

In addition to the litigation described above, the Company is a defendant in lawsuits from time to time in the normal course of business. While the results of litigation and claims cannot be predicted with certainty, the Company believes the reasonably possible losses of such matters, individually and in the aggregate, are not material. Additionally, the Company believes the probable final outcome of such matters will not have a material adverse effect on the Company’s consolidated financial position, results of operations, cash flows or liquidity.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

PRICE RANGE OF COMMON STOCK

The Company's common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "SD." The range of high and low sales prices for its common stock for the periods indicated, as reported by the NYSE, is as follows:

	High	Low
2013		
Fourth Quarter	$6.90	$5.26
Third Quarter	$5.99	$4.83
Second Quarter	$5.39	$4.56
First Quarter	$7.24	$5.27
2012		
Fourth Quarter	$7.49	$4.81
Third Quarter	$7.80	$6.00
Second Quarter	$8.19	$5.55
First Quarter	$9.00	$6.75

On February 21, 2014, there were 293 record holders of the Company's common stock.

The Company has neither declared nor paid any cash dividends on its common stock, and it does not anticipate declaring any dividends on its common stock in the foreseeable future. The Company expects to retain cash for the operation and expansion of its business, including exploration, development and production activities. In addition, the terms of the Company's indebtedness restrict its ability to pay dividends to holders of its common stock. Accordingly, if the Company's dividend policy were to change in the future, its ability to pay dividends would be subject to these restrictions and the Company's then-existing conditions, including its results of operations, financial condition, contractual obligations, capital requirements, business prospects and other factors deemed relevant by its Board of Directors.

PERFORMANCE GRAPH

The following graph compares the cumulative total return to stockholders on SandRidge common stock relative to the cumulative total returns of the S&P Oil and Gas Exploration and Production Index and the S&P 500 Index from January 1, 2009 through December 31, 2013. The graph assumes that the value of the investment in the Company's common stock and in each of the indexes was $100.00 on January 1, 2009.

The performance graph above is furnished and not filed for purposes of Section 18 of the Exchange Act and will not be incorporated by reference into any registration statement filed under the Securities Act unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

ISSUER PURCHASES OF EQUITY SECURITIES

As part of the Company's restricted stock program, the Company makes required tax payments on behalf of employees when their stock awards vest and then withholds a number of vested shares of common stock having a value on the date of vesting equal to the tax obligation. The shares withheld are initially recorded as treasury stock and are then immediately retired as repurchased. See "Note 16—Equity" to the Company's consolidated financial statements in Item 8 of this report for further discussion of treasury stock. During the quarter ended December 31, 2013, the following shares of common stock were withheld in satisfaction of tax withholding obligations arising from the vesting of restricted stock:

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1, 2013 — October 31, 2013	60,987	$6.19	N/A	N/A
November 1, 2013 — November 31, 2013	8,329	$6.33	N/A	N/A
December 1, 2013 — December 31, 2013	6,009	$5.78	N/A	N/A

Item 6. Selected Financial Data

The following table sets forth, as of the dates and for the periods indicated, the Company's selected financial information. The Company's financial information is derived from its audited consolidated financial statements for such periods. The financial data includes the results of the Company's acquisitions and divestitures, including the divestiture of the Permian Properties in February 2013, the acquisition of oil and natural gas properties in the Gulf of Mexico in June 2012, the Dynamic Acquisition in April 2012, the acquisition of Arena Resources, Inc. ("Arena") in July 2010 and the acquisition of oil and natural gas properties from Forest Oil Corporation in December 2009. The information should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of this report and the Company's consolidated financial statements and notes thereto contained in "Financial Statements and Supplementary Data" in Item 8 of this report. The following information is not necessarily indicative of the Company's future results.

	Year Ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands, except per share data)				
Statement of Operations Data					
Revenues	$1,983,388	$2,730,965	$1,415,213	$931,736	$591,044
Expenses					
Production	516,427	477,154	322,877	237,863	169,880
Production taxes	32,292	47,210	46,069	29,170	4,010
Cost of sales	57,118	68,227	65,654	22,368	28,380
Midstream and marketing	53,644	39,669	66,007	90,149	80,608
Construction contract	23,349	796,323	—	—	—
Depreciation and depletion—oil and natural gas	567,732	568,029	317,246	265,914	168,919
Depreciation and amortization—other	62,136	60,805	53,630	50,776	50,865
Accretion of asset retirement obligations	36,777	28,996	9,368	9,421	7,108
Impairment	26,280	316,004	2,825	—	1,707,150
General and administrative(1)	330,425	241,682	148,643	179,565	100,256
Loss (gain) on derivative contracts	47,123	(241,419)	(44,075)	50,872	(147,527)
Loss (gain) on sale of assets	399,086	3,089	(2,044)	2,424	26,419
Total expenses	2,152,389	2,405,769	986,200	938,522	2,196,068
(Loss) income from operations	(169,001)	325,196	429,013	(6,786)	(1,605,024)
Other income (expense)					
Interest expense	(270,234)	(303,349)	(237,332)	(247,442)	(185,316)
Bargain purchase gain	—	122,696	—	—	—
Loss on extinguishment of debt	(82,005)	(3,075)	(38,232)	—	—
Income from equity investments	—	—	—	—	1,020
Other income, net	12,445	4,741	3,122	2,558	7,272
Total other expense	(339,794)	(178,987)	(272,442)	(244,884)	(177,024)
(Loss) income before income taxes	(508,795)	146,209	156,571	(251,670)	(1,782,048)
Income tax expense (benefit)	5,684	(100,362)	(5,817)	(446,680)	(8,716)
Net (loss) income	(514,479)	246,571	162,388	195,010	(1,773,332)
Less: net income attributable to noncontrolling interest	39,410	105,000	54,323	4,445	2,258
Net (loss) income attributable to SandRidge Energy, Inc.	(553,889)	141,571	108,065	190,565	(1,775,590)
Preferred stock dividends	55,525	55,525	55,583	37,442	8,813
(Loss applicable) income available to SandRidge Energy, Inc. common stockholders	$(609,414)	$86,046	$52,482	$153,123	$(1,784,403)

(Loss) earnings per share					
Basic	$(1.27)	$0.19	$0.13	$0.52	$(10.20)
Diluted	$(1.27)	$0.19	$0.13	$0.52	$(10.20)
Weighted average number of common shares outstanding					
Basic	481,148	453,595	398,851	291,869	175,005
Diluted	481,148	456,015	406,645	315,349	175,005

(1) Includes employee termination benefits.

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	As of December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$814,663	$309,766	$207,681	$5,863	$7,861
Property, plant and equipment, net	$6,307,675	$8,479,977	$5,389,424	$4,733,865	$2,433,643
Total assets	$7,684,795	$9,790,731	$6,219,609	$5,231,448	$2,780,317
Total debt	$3,194,907	$4,301,083	$2,814,176	$2,909,086	$2,578,938
Total equity	$3,175,627	$3,862,455	$2,548,950	$1,547,483	$(195,905)
Total liabilities and equity	$7,684,795	$9,790,731	$6,219,609	$5,231,448	$2,780,317

There have been no cash dividends declared or paid on the Company’s common stock.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis is intended to help the reader understand the Company's business, financial condition, results of operations, liquidity and capital resources. This discussion and analysis should be read in conjunction with other sections of this report, including: "Business" in Item 1, "Selected Financial Data" in Item 6 and "Financial Statements and Supplementary Data" in Item 8. The Company's discussion and analysis relates to the following subjects:

- Overview;
- Results by Segment;
- Consolidated Results of Operations;
- Liquidity and Capital Resources;
- Valuation Allowance; and
- Critical Accounting Policies and Estimates.

Overview

SandRidge Energy, Inc. is an oil and natural gas company with a principal focus on exploration and production activities in the Mid-Continent region of the United States. The Company owns and operates additional interests in west Texas and owned interests in the Gulf of Mexico and Gulf Coast until February 2014, as discussed under "2014 Developments and Outlook" below. 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 disposal system, an electrical transmission system and a drilling rig and related oil field services business.

SandRidge's mission is to become a high-return, growth-oriented resource conversion company focused in the Mid-Continent region of the United States. In 2013, the Company began a capital allocation process, during which the Company identified its competitive advantages, such as its industry leading cost structure, subsurface knowledge, existing infrastructure and broader infrastructure capabilities and size and scale, all in the Mid-Continent area. As a result of that process, the decision was made to enhance the Company's focus in the Mid-Continent, divest the Gulf Properties, and redeploy capital into onshore areas where the Company has a more extensive opportunity set, and over a 10-year inventory of high return drilling locations.

2013 Operational Highlights

Operational highlights for 2013 include the following:

- Drilled 483 wells, excluding salt water disposal wells, in the Mid-Continent area. Mid-Continent properties contributed approximately 17.8 MMBoe, or 52.7%, of the Company's total production in 2013 compared to approximately 11.0 MMBoe, or 32.9%, in 2012.
- Gulf of Mexico properties acquired during the second quarter of 2012 contributed production of approximately 9.2 MMBoe, or 27.3% of the Company's total production in 2013 compared to approximately 7.0 MMBoe, or 20.8% of total production in 2012.
- Permian Properties divested in February 2013, as discussed below, contributed 3.4% of total production in 2013 compared to 25.8% of total production in 2012.
- Total production for 2013 was comprised of approximately 42.3% oil, 50.9% natural gas and 6.8% NGLs compared to 47.3% oil, 46.5% natural gas and 6.2% NGLs in 2012.

2013 Transactions

Sale of Permian Properties. On February 26, 2013, the Company sold 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, discussed below, and has used and expects to use the remaining proceeds to fund its 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.

Production, revenues and direct operating expenses of the Permian Properties were as follows as of and for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013(1)	2012	2011
Production (MBoe)	1,148	8,667	8,871
Revenues (in thousands)	$68,027	$566,075	$614,666
Direct operating expenses (in thousands)	$17,453	$130,337	$144,066

(1) Includes activity through February 26, 2013, the date of sale.

Redemption of Senior Fixed Rate Notes. In March 2013, the Company redeemed $365.5 million aggregate principal amount of its 9.875% Senior Notes due 2016 and $750.0 million aggregate principal amount of its 8.0% Senior Notes due 2018 for total consideration of $1,061.34 per $1,000 principal amount and $1,052.77 per $1,000 principal amount, respectively. The premium paid to redeem these notes and the expense incurred to write off the remaining associated unamortized debt issuance costs resulted in a loss on extinguishment of debt of $82.0 million for the year ended December 31, 2013. The redemption of these senior notes resulted in a reduction in interest expense for the year ended December 31, 2013 of approximately $72.8 million.

2014 Developments and Outlook

Developments

Sale of Gulf of Mexico and Gulf Coast Properties. On February 25, 2014, the Company sold certain of its subsidiaries that own the Gulf Properties, for $750.0 million, subject to purchase price and post-closing adjustments, and the buyer's assumption of approximately $370.0 million of related asset retirement obligations. The Company retained a 2.0% overriding royalty interest in certain exploration prospects. The Company expects to use 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 cash payments of approximately $69.6 million.

For further discussion of the sale, see "Note 21—Subsequent Events" to the consolidated financial statements included in Item 8 of this report.

Production, proved reserves, PV-10, revenues and expenses, including direct operating expenses, depletion, accretion of asset retirement obligations, and general and administrative expenses, for the Gulf Properties were as follows as of and for the year ended December 31, 2013:

Production (MBoe)	10,082
Proved reserves (MBoe)	56,797
PV-10 (in thousands)(1)	$1,088,872
Revenues (in thousands)	$627,236
Operating expenses (in thousands)	$491,991

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(1) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil, natural gas and NGL reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using 12-month average prices for the year ended December 31, 2013. PV-10 differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of the Gulf Properties. The following table provides a reconciliation of the estimated Standardized Measure attributable to the Gulf Properties to PV-10 attributable to the Gulf Properties as of December 31, 2013 (in thousands):

Standardized Measure of Discounted Net Cash Flows(a)	$842,493
Present value of future income tax discounted at 10%	246,379
PV-10	$1,088,872

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(a) Standardized Measure was determined by allocating the Company’s Standardized Measure to the Gulf Properties based on the PV-10 attributable to the Gulf Properties relative to the Company’s total PV-10.

Outlook

In 2014, the Company plans to continue the capital allocation process it began in 2013, focusing on highest return projects, coupled with an enhanced capital discipline, while utilizing its identified competitive advantages. The Company’s 2014 capital expenditures budget is approximately $1.5 billion, with approximately $1.4 billion designated for exploration and production activities. Based on this current capital budget for 2014, the Company estimates an approximate 25% increase in 2014 production from 2013 production levels, excluding 2013 production associated with the Gulf Properties sold in February 2014 and Permian Properties sold in February 2013.

Results by Segment

The Company operates in three business segments: exploration and production, drilling and oil field services and midstream services. These segments represent the Company’s three main business units, each offering different products and services. The exploration and production segment is engaged in the exploration and production of oil and natural gas properties and includes the activities of the Royalty Trusts. The drilling and oil field services segment is engaged in the contract drilling of oil and natural gas wells and provides various oil field services. The midstream services segment is engaged in the purchasing, gathering, treating and selling of natural gas and coordinates the delivery of electricity for the Company’s exploration and production operations in the Mid-Continent.

Management evaluates the performance of the Company’s business segments based on income (loss) from operations. Results of these measurements provide important information to the Company about the activity, profitability and contributions of each of the Company’s lines of business. The Company’s business segments results for the years ended December 31, 2013, 2012 and 2011 are discussed below.

Exploration and Production Segment

The Company generates the majority of its consolidated revenues and cash flow from the production and sale of oil, natural gas and NGLs. The Company's revenues, profitability and future growth depend substantially on prevailing prices for oil, natural gas and NGLs and on the Company's ability to find and economically develop and produce its reserves. The primary factors affecting the financial results of the Company's exploration and production segment are the prices the Company receives for its oil, natural gas and NGL production, the quantity of oil, natural gas and NGLs it produces and changes in the fair value of commodity derivative contracts. Prices for oil, natural gas and NGLs fluctuate widely and are difficult to predict. To provide information on the general trend in pricing, the average annual NYMEX prices for oil and natural gas during the years ended December 31, 2013, 2012, 2011, 2010 and 2009 are presented in the following table:

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Oil (per Bbl)	$98.05	$94.15	$95.11	$79.61	$62.09
Natural gas (per Mcf)	$3.73	$2.83	$4.03	$4.38	$4.16

In order to reduce the Company's exposure to price fluctuations, the Company enters into commodity derivative contracts for a portion of its anticipated future oil and natural gas production as discussed in "Item 7A. Quantitative and Qualitative Disclosures About Market Risk." Reducing the Company's exposure to price volatility mitigates the risk that it will not have adequate funds available for its capital expenditure programs.

Set forth in the table below is financial, production and pricing information for the exploration and production segment for the years ended December 31, 2013, 2012 and 2011.

	Year Ended December 31,		
	2013	2012	2011
Results (in thousands)			
Revenues			
Oil	$1,393,360	$1,456,590	$902,384
NGL	80,555	69,306	81,938
Natural gas	346,363	233,386	242,472
Construction contract	—	796,323	—
Other	14,202	15,939	10,771
Inter-segment revenue	(320)	(403)	(265)
Total revenues	1,834,160	2,571,141	1,237,300
Operating expenses			
Production	519,546	480,001	324,637
Production taxes	32,292	47,210	46,069
Construction contract	—	796,323	—
Depreciation and depletion—oil and natural gas	567,732	568,029	317,246
Accretion of asset retirement obligations	36,777	28,996	9,368
Impairment	—	235,396	—
Loss (gain) on derivative contracts	47,123	(241,419)	(44,075)
Loss (gain) on sale of assets	398,543	3,499	(92)
Other operating expenses	169,638	134,962	63,030
Total operating expenses	1,771,651	2,052,997	716,183
Income from operations	$62,509	$518,144	$521,117
Production data			
Oil (MBbls)	14,279	15,868	9,992
NGL (MBbls)	2,291	2,094	1,838
Natural gas (MMcf)	103,233	93,549	69,306
Total volumes (MBoe)	33,776	33,553	23,381
Average daily total volumes (MBoe/d)	92.5	91.7	64.1
Average prices—as reported(1)			
Oil (per Bbl)	$97.58	$91.79	$90.31
NGL (per Bbl)	$35.16	$33.10	$44.58
Natural gas (per Mcf)	$3.36	$2.49	$3.50
Total (per Boe)	$53.89	$52.43	$52.47
Average prices—including impact of derivative contract settlements(2)			
Oil (per Bbl)	$98.90	$97.53	$82.26
NGL (per Bbl)	$35.16	$33.10	$44.58
Natural gas (per Mcf)	$3.46	$2.46	$3.27
Total (per Boe)	$54.79	$55.04	$48.35

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(1) Prices represent actual average prices for the periods presented and do not include the impact of derivative transactions.

(2) Excludes settlements of commodity derivative contracts prior to their contractual maturity.

For a discussion of reserves, PV-10 and reconciliation to Standardized Measure, see “Business—Business Segments and Primary Operations—Proved Reserves” in Item 1 of this report.

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The table below presents production by area of operation for the years ended December 31, 2013, 2012 and 2011 and illustrates the impact of (i) the Company's continued development of its Mid-Continent assets, (ii) the Company's purchase of properties located in the Gulf of Mexico during the second quarter of 2012 and (iii) the sale of the Permian Properties in February 2013.

	Year Ended December 31,								
	2013			2012			2011		
	Production (MBoe)	% of Total Production		Production (MBoe)	% of Total Production		Production (MBoe)	% of Total Production	
Mid-Continent	17,783	52.7	%	11,039	32.9	%	4,884	20.9	%
Gulf of Mexico / Gulf Coast	10,082	29.8	%	8,110	24.2	%	1,434	6.1	%
Permian Basin	3,366	10.0	%	10,963	32.6	%	10,517	45.0	%
Other - west Texas	2,545	7.5	%	3,441	10.3	%	6,546	28.0	%
Total	33,776	100.0	%	33,553	100.0	%	23,381	100.0	%

Revenues

Exploration and production segment revenues from oil, natural gas and NGL sales increased by a combined $61.0 million, or 3.5% for the year ended December 31, 2013 compared to 2012, primarily as a result of increases in average prices received for oil and natural gas, and an increase in natural gas production of 9.7 Bcf, or 10.4%. Total production remained relatively unchanged in 2013 compared to 2012; however, natural gas comprised a larger portion of total production in 2013 as production from the Mid-Continent and Gulf of Mexico, which contains a higher percentage of natural gas than production from the Permian Basin, comprised a larger percentage of total production in 2013.

Exploration and production segment revenues from oil, natural gas and NGL sales increased by a combined $532.5 million, or 43.4% in the year ended December 31, 2012 from 2011, primarily as a result of a 5.9 MMBbl, or 58.8% increase in oil production. Natural gas production also increased 24.2 Bcf, or 35.0%, but the effect of this increase was more than offset by a decrease in average price received of $1.01 per Mcf, or 28.9%. The increase in oil and natural gas production was primarily due to the acquisition of properties located in the Gulf of Mexico during the second quarter of 2012 combined with increased drilling in the Mid-Continent, where, during 2012, the Company completed and commenced production on 377 gross (269 net) wells.

During the fourth quarter of 2012, the Company substantially completed construction of the Century Plant and recognized construction contract revenue and costs equal to $796.3 million, which reflects agreed upon change orders and scope revisions to the original contract. Contract losses incurred on the construction of the Century Plant were recorded as development costs within the Company's oil and natural gas properties. As of December 31, 2012, the Company had recorded a total of $180.0 million to its oil and natural gas properties for the loss identified based on costs incurred in excess of contract amounts.

Operating Expenses

Production expense includes the costs associated with the Company's exploration and production activities, including, but not limited to, lease operating expense and treating costs. Production expenses increased $39.5 million, or 8.2%, in 2013 from 2012 primarily due to a $32.7 million shortfall penalty related to the under delivery of CO_2, in accordance with the terms of the Company's 30-year treating agreement with Occidental, for the year ended December 31, 2013. On a per Boe basis, production expense for 2013 increased $1.07 per Boe, or 7.5%, to $15.38 per Boe during the year ended December 31, 2013 from $14.31 per Boe in 2012. This increase is primarily a result of the shortfall penalty and, to a lesser extent, higher costs associated with production from properties located in the Gulf of Mexico, which comprised a larger percentage of total production in 2013. Production expenses increased $155.4 million, or 47.9%, in

2012 from 2011 primarily due to operating expenses associated with oil and natural gas properties located in the Gulf of Mexico that were acquired during the second quarter of 2012 and additional oil wells located in the Mid-Continent that began producing during 2012.

Production taxes decreased by approximately $14.9 million, or 31.6% for the year ended December 31, 2013 compared to 2012 and increased only slightly in 2012 compared to 2011, as production from the Mid-Continent and Gulf Properties comprised approximately 82.5% of total 2013 production compared to approximately 57.1% of 2012 production and approximately 27.0% of 2011 production. Production from the Gulf of Mexico is not subject to production taxes. Additionally, wells drilled in the Mississippian formation in Oklahoma are part of a tax credit incentive program that reduces the combined statutory rates applicable to the first four years of production from such wells.

Depreciation and depletion for the Company's oil and natural gas properties was consistent for the years ended December 31, 2013 and 2012. Depreciation and depletion for the Company's oil and natural gas properties increased $250.8 million for the year ended December 31, 2012 from the same period in 2011. The increase was due to a 43.5% increase in the Company's combined production volume as well as an increase in the depreciation and depletion rate per Boe to $16.93 in 2012 from $13.57 per Boe in 2011 that resulted primarily from the acquisition of properties located in the Gulf of Mexico during 2012, which generally have shorter depletable lives than onshore properties.

Accretion of asset retirement obligations increased $7.8 million for the year ended December 31, 2013 from 2012, and increased $19.6 million for the year ended December 31, 2012 from 2011 as a result of the increase in future plugging and abandonment obligations associated with the oil and natural gas properties located in the Gulf of Mexico that were acquired during the second quarter of 2012.

During the year ended December 31, 2012, the Company recorded a $235.4 million impairment to the carrying value of goodwill. Primarily as a result of a decrease in the Company's probable reserves as of December 31, 2012, which are one of the significant components in the determination of the fair value of the applicable reporting unit, the carrying value of the reporting unit exceeded its fair value such that the entire carrying value of the Company's goodwill was impaired. For additional information regarding the goodwill impairment, see "Note 8—Impairment" to the Company's consolidated financial statements in Item 8 of this report.

The Company recorded loss (gain) on commodity derivative contracts of $47.1 million, $(241.4) million and $(44.1) million for the years ended December 31, 2013, 2012 and 2011, respectively, which are included in income from operations for the exploration and production segment. Included in the loss (gain) on commodity derivative contracts for the years ended December 31, 2013, 2012 and 2011 are net cash (receipts) payments upon contract settlement of $(3.2) million, $(100.7) million and $37.6 million, respectively. For the year ended December 31, 2013, $29.6 million of cash payments related to settlements of commodity derivative contracts with contractual maturities after the year in which they were settled ("early settlements") as a result of the sale of the Permian Properties. For the year ended December 31, 2012, the Company had a non-cash loss of $117.1 million resulting from the amendment of certain 2012 derivative contracts to contracts maturing in 2014 and 2015.

The Company's derivative contracts are not designated as accounting hedges and, as a result, gains or losses on commodity derivative contracts are recorded each quarter as a component of operating expenses. Internally, management views the settlement of derivative contracts at contractual maturity as adjustments to the price received for oil and natural gas production to determine "effective prices." Gains or losses on early settlements and losses related to amendments of contracts are not considered in the calculation of effective prices. In general, cash is received on settlement of contracts due to lower oil and natural gas prices at the time of settlement compared to the contract price for the Company's oil and natural gas price swaps, and cash is paid on settlement of contracts due to higher oil and natural gas prices at the time of settlement compared to the contract price for the Company's oil and natural gas price swaps.

Loss on sale of assets increased $395.0 million for the year ended December 31, 2013 compared to the same period in 2012, primarily as a result of the $398.9 million loss on the sale of the Permian Properties in February 2013.

See "Consolidated Results of Operations" below for a discussion of other operating expenses.

Drilling and Oil Field Services Segment

The financial results of the Company's drilling and oil field services segment depend primarily on demand and prices that can be charged for its services. On a consolidated basis, drilling and oil field service revenues earned and expenses incurred in performing services for third parties, including third-party working interests in wells the

Company operates, are included in drilling and services revenues and cost of sales. Drilling and oil field service revenues earned and expenses incurred in performing services for the Company’s own account are eliminated in consolidation. The primary factors affecting the results of the Company’s drilling and oil field services segment are the rates received on rigs drilling for third parties, the number of days drilling for third parties and the amount of oil field services provided to third parties.

Set forth in the table below is financial and operational information for the drilling and oil field services segment for the years ended December 31, 2013, 2012 and 2011.

	Year Ended December 31,		
	2013	2012	2011
Results (in thousands)			
Revenues	$187,456	$379,345	$390,485
Inter-segment revenue	(120,815)	(262,712)	(287,187)
Total revenues	66,641	116,633	103,298
Operating expenses	95,692	104,722	92,957
Impairment	11,104	—	—
(Loss) income from operations	$(40,155)	$11,911	$10,341
Drilling rig statistics			
Average number of operational rigs owned during the period	29.0	30.0	30.8
Average number of rigs working for third parties	4.4	9.4	10.0
Number of days drilling for third parties	1,603	2,613	3,673
Average drilling revenue per day per rig drilling for third parties(1)	$14,610	$16,919	$15,215
Rig status as of December 31			
Working for SandRidge	11	14	20
Working for third parties(2)	6	10	10
Idle (3)	10	6	—
Total operational	27	30	30
Non-operational(4)	3	1	1
Total rigs	30	31	31

(1) Represents revenues from rigs working for third parties, excluding stand-by revenue, divided by the total number of days such drilling rigs were used by third parties during the period, excluding revenues for related rental equipment.

(2) Includes five rigs receiving stand-by rates from third parties at December 31, 2012.

(3) The company's rigs are primarily intended to drill for its own account; as such, the number of idle rigs does not significantly impact the consolidated results of operations.

(4) Non-operational rigs at December 31, 2013 are held for sale. Non-operational rig at December 31, 2012 and 2011 was stacked.

Drilling and oil field services segment revenues decreased $50.0 million, for the year ended December 31, 2013 from 2012. The decrease in revenues was primarily attributable to a decrease in the average number of rigs working for third parties and a decrease in supplies sold to, and oil field services work performed for, wells that had been operated by the Company in the Permian Basin prior to their sale. Drilling and oil field services segment operating expenses decreased $9.0 million during the year ended December 31, 2013 compared to 2012 due primarily to the decrease in work performed in the Permian Basin, which was significantly offset by costs associated with maintenance performed on rigs that were stacked as a result of the sale of the Permian Properties. For the year ended December 31, 2013, the Company recorded an impairment of approximately $11.1 million on certain drilling assets identified for sale in order to adjust their carrying values to fair value. The impairment and decrease in revenue resulted in a loss from operations of $40.2 million for the year ended December 31, 2013.

Drilling and oil field services segment revenues and expenses increased $13.3 million and $11.8 million, respectively, for the year ended December 31, 2012 from 2011. The increase in revenues and expenses was primarily attributable to an increase in supplies sold to, and oil field services work performed for, Company-operated wells in the

Mid-Continent with higher third-party working interest percentages during the year ended December 31, 2012. While the average drilling revenue per day per rig working for third parties increased during the year ended December 31, 2012 compared to 2011, this was more than offset by a decrease in the number of days drilling for third parties. The overall increase in revenue resulted in income from operations of $11.9 million in the year ended December 31, 2012 compared to income from operations of $10.3 million in 2011.

Midstream Services Segment

Midstream services segment revenues consist mostly of revenue from gas marketing, which is a very low-margin business, and revenues from coordinating the delivery of electricity to the Company's exploration and production operations in the Mid-Continent area.

Gas Marketing. On a consolidated basis, midstream and marketing revenues include natural gas sold to third parties and the fees the Company charges to gather, compress and treat this natural gas. Gas marketing operating costs represent payments made to third parties for the proceeds from the sale of natural gas owned by such parties, net of any applicable margin, and actual costs the Company charges to gather, compress and treat the natural gas. In general, natural gas purchased and sold by the Company's midstream services segment is priced at a published daily or monthly index price. Midstream gas services are primarily undertaken to realize incremental margins on natural gas purchased at the wellhead and to provide value-added services to customers.

Electrical Provision. The Company constructed an electrical transmission system in the Mid-Continent area to provide electricity for use in the Company's exploration and production operations at a lower cost than electricity provided by on-site generation. On a consolidated basis, revenues and expenses from the electrical transmission system relate to electricity provided to third-party working interest owners in Company operated wells in the Mid-Continent.

Gas Treating Plants. The Company owns and operates two gas treating plants in west Texas, which remove CO_2 from natural gas production and deliver residue gas to nearby pipelines. Throughout 2012, the Company diverted its high CO_2 natural gas production from its gas treating plants to the Century Plant while it was being tested and commissioned. Upon substantial completion of the Century Plant in late 2012, natural gas volumes delivered by the Company for processing at the Century Plant became subject to the terms of the 30-year treating agreement with Occidental, which contains minimum CO_2 delivery requirements. All natural gas produced in the WTO during 2013 was processed at the Century Plant. Due to the continued decline in natural gas production in the WTO resulting from the lack of drilling activity in the area, volumes currently produced in the WTO and delivered to the Century Plant for processing are not sufficient to use all of the available treating capacity at the Century Plant. Due to the sensitivity of drilling to market prices for natural gas, drilling activity in the WTO will likely remain very limited if natural gas prices remain low. As a result, the Company currently anticipates little to no use of its treating plants in future periods.

The primary factors affecting the results of the Company's midstream services segment are the quantity of natural gas the Company gathers, treats and markets and the prices it pays and receives for natural gas as well as the rates charged and volumes delivered by the electrical transmission system.

Set forth in the table below is financial information for the midstream services segment for the years ended December 31, 2013, 2012 and 2011.

	Year Ended December 31,		
	2013	2012	2011
Results (in thousands)			
Operating revenues	$156,640	$116,659	$183,912
Construction contract	23,349	—	—
Inter-segment revenue	(100,529)	(77,824)	(118,731)
Total revenues	79,460	38,835	65,181
Operating expenses	73,744	52,179	75,331
Construction contract	23,349	—	—
Impairment	3,934	59,683	2,825
Loss from operations	$(21,567)	$(73,027)	$(12,975)

Gas Marketed			
Volumes (MMcf)	8,006	9,367	14,807
Price	$3.56	$2.63	$3.88

Midstream services segment operating revenues and expenses increased $17.3 million and $21.6 million, respectively, for the year ended December 31, 2013 from the same period in 2012. These increases in operating revenue and expenses were due to an increase of $0.95 per Mcf in the average price received for natural gas purchased and marketed in west Texas during the year ended December 31, 2013, respectively, and an increase in revenue from and expenses related to electrical transmission services provided by the Company's expanded electrical infrastructure in the Mid-Continent to third-party working interest owners. These increases were slightly offset by a 1.4 Bcf decrease in third-party volumes processed and marketed for the year ended December 31, 2013 compared to the year ended December 31, 2012 as a result of decreased natural gas production in west Texas.

Midstream services segment revenues and operating expenses, excluding impairment, for the year ended December 31, 2012 decreased $26.3 million and $23.2 million, respectively, from the same period in 2011. These decreases in revenue and operating expenses were due to a 5.4 Bcf decrease in third-party volumes the Company processed and marketed as a result of decreased natural gas production in west Texas and a decrease in natural gas prices. These decreases were partially offset by an increase in revenue from and expenses related to electrical transmission as a result of the expansion of the Company's electrical infrastructure in the Mid-Continent in 2012.

During the second quarter of 2013, the Company substantially completed the construction of a series of electrical transmission expansion and upgrade projects for a third party and, as a result, recognized construction contract revenue and costs equal to $23.3 million. For more information about these projects, see "Note 11— Construction Contracts" to the Company's consolidated financial statements in Item 8 of this report.

Midstream services segment expenses for the years ended December 31, 2013 and 2012 include impairments of $3.9 million and $59.7 million, respectively, on its natural gas treating plants in west Texas due to the anticipation that their future use would be limited as discussed under Gas Treating Plants above. The $59.7 million impairment in 2012 resulted in a loss from operations of $73.0 million for the year ended December 31, 2012 compared to $13.0 million in 2011.

Consolidated Results of Operations

Revenues

The Company's consolidated revenues for the years ended December 31, 2013, 2012 and 2011 are presented in the table below.

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Revenues			
Oil, natural gas and NGL	$1,820,278	$1,759,282	$1,226,794
Drilling and services	66,586	116,633	103,298
Midstream and marketing	58,304	40,486	66,690
Construction contract	23,349	796,323	—
Other	14,871	18,241	18,431
Total revenues(1)	$1,983,388	$2,730,965	$1,415,213

(1) Includes $199.3 million, $181.2 million and $69.6 million of revenues attributable to noncontrolling interests in consolidated variable interest entities ("VIEs"), after considering the effects of intercompany eliminations, for the years ended December 31, 2013, 2012 and 2011, respectively.

The Company's primary sources of revenue are discussed in "Results by Segment." See discussion of oil, natural gas and NGL and construction contract revenues under "Results by Segment—Exploration and Production Segment," discussion of drilling and services revenues under "Results by Segment—Drilling and Oil Field Services Segment" and discussion of significant midstream and marketing and construction contract revenues under "Results by Segment—Midstream

Services Segment."

Expenses

The Company's consolidated expenses for the years ended December 31, 2013, 2012 and 2011 are presented below.

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Expenses			
Production	$516,427	$477,154	$322,877
Production taxes	32,292	47,210	46,069
Cost of sales	57,118	68,227	65,654
Midstream and marketing	53,644	39,669	66,007
Construction contract	23,349	796,323	—
Depreciation and depletion—oil and natural gas	567,732	568,029	317,246
Depreciation and amortization—other	62,136	60,805	53,630
Accretion of asset retirement obligations	36,777	28,996	9,368
Impairment	26,280	316,004	2,825
General and administrative	207,920	241,682	148,643
Employee termination benefits	122,505	—	—
Loss (gain) on derivative contracts	47,123	(241,419)	(44,075)
Loss (gain) on sale of assets	399,086	3,089	(2,044)
Total expenses(1)	$2,152,389	$2,405,769	$986,200

(1) Includes $157.0 million, $75.4 million and $15.1 million of expenses attributable to noncontrolling interests in consolidated VIEs, after considering the effects of intercompany eliminations, for the years ended December 31, 2013, 2012 and 2011, respectively. The expenses attributable to noncontrolling interest in consolidated VIEs for 2013 include $71.7 million of allocated loss on sale of assets associated with the sale of the Permian Properties.

See discussion of production expenses, production taxes, construction contract expenses, depreciation and depletion—oil and natural gas, accretion of asset retirement obligations, loss (gain) on derivative contracts and loss (gain) on sale of assets under "Results by Segment—Exploration and Production Segment," discussion of cost of sales under "Results by Segment— Drilling and Oil Field Services Segment" and discussion of midstream and marketing and construction contract expense under "Results by Segment—Midstream Services Segment."

Impairment expense for the year ended December 31, 2013 primarily consists of an $11.1 million impairment of certain drilling assets and a $2.9 million impairment of a corporate asset based on plans to sell these assets in 2013 and 2014. Additionally, impairment expense for the year ended December 31, 2013 includes $12.2 million of impairment on certain midstream pipe inventory, natural gas compressors, gas treating plants and a CO_2 compressor station after determining that their future use was limited. Impairment expense for the year ended December 31, 2012 consists primarily of a $235.4 million impairment of goodwill and a $79.3 million impairment of the Company's gas treating plants and CO_2 compression facilities recorded in connection with the completion of the Century Plant. In 2011, the Company recorded an impairment of $2.8 million on certain midstream compressor assets as their future use was determined to be limited. See "Note 8—Impairment" to the Company's consolidated financial statements in Item 8 of this report for additional information regarding these impairments.

General and administrative expenses decreased $33.8 million, or 14.0% for the year ended December 31, 2013 from 2012, primarily due to decreases of $23.5 million and $12.0 million in legal settlement and acquisition costs, respectively. Additionally, there were decreases in promotional and advertising costs and compensation as a result of corporate cost cutting measures and a decrease in headcount during 2013. These decreases were partially offset by a $20.4 million increase in costs related to a stockholder consent solicitation. General and administrative expenses increased $93.0 million, or 62.6% for the year ended December 31, 2012 from 2011. This increase is due primarily to a $32.3 million increase in compensation costs as a result of an increase in the number of Company employees; a $20.0 million legal settlement, as discussed in “Note 15—Commitments and Contingencies” to the Company’s consolidated financial statements in Item 8 of this report; a $19.6 million increase in legal and consulting fees, including costs associated with stockholder litigation and activism activities; $13.2 million in acquisition costs associated with the oil and natural gas properties located in the Gulf of Mexico that were acquired during the second quarter of 2012; and a $7.1 million increase in advertising expense.

Employee termination benefits of $122.5 million for the year ended December 31, 2013 represent severance costs associated with former Company executives. Of the total employee termination benefits, approximately $99.3 million, including amounts associated with the accelerated vesting of restricted stock awards, were attributable to the Company's former Chairman and CEO.

Other Income (Expense), Taxes and Net Income Attributable to Noncontrolling Interest

The Company's other income (expense), taxes and net income attributable to noncontrolling interest for the years ended December 31, 2013, 2012 and 2011 are reflected in the table below.

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Other income (expense)			
Interest expense	$(270,234)	$(303,349)	$(237,332)
Bargain purchase gain	—	122,696	—
Loss on extinguishment of debt	(82,005)	(3,075)	(38,232)
Other income, net	12,445	4,741	3,122
Total other expense	(339,794)	(178,987)	(272,442)
(Loss) income before income taxes	(508,795)	146,209	156,571
Income tax expense (benefit)	5,684	(100,362)	(5,817)
Net (loss) income	(514,479)	246,571	162,388
Less: net income attributable to noncontrolling interest	39,410	105,000	54,323
Net (loss) income attributable to SandRidge Energy, Inc.	$(553,889)	$141,571	$108,065

Interest expense for the years ended December 31, 2013, 2012 and 2011 consisted of the following:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Interest expense			
Interest expense on debt	$275,784	$289,094	$223,461
Amortization of debt issuance costs, discounts and premium	11,127	16,980	13,755
Dynamic Acquisition committed financing fee	—	10,875	—
Loss on interest rate swaps	14	1,189	3,168
Capitalized interest	(16,691)	(14,789)	(3,052)
Total interest expense	$270,234	$303,349	$237,332

Total interest expense decreased $33.1 million for the year ended December 31, 2013 compared to 2012, primarily as a result of a reduction in interest expense associated with the senior notes repurchased and redeemed in 2012 and in the first quarter of 2013, which was partially offset by the incurrence of interest on the senior notes issued in 2012 for the full year of 2013. Interest expense increased $66.0 million for the year ended December 31, 2012 compared to 2011, primarily as a result of issuances of senior notes in 2012 and 2011, partially offset by a reduction in interest expense associated with senior notes repurchased and redeemed in 2012 and 2011. In addition, as a result of the Company electing to issue senior notes to fund the cash portion of the Dynamic Acquisition rather than utilize previously secured committed financing, fees associated with the committed financing of $10.9 million were fully expensed during the year ended December 31, 2012. See "Note 12—Long-Term Debt" to the Company's consolidated financial statements in Item 8 of this report for additional discussion of the Company's long-term debt transactions in 2013 and 2012.

The bargain purchase gain recorded during the year ended December 31, 2012 resulted from the excess of net assets acquired over consideration paid in the Dynamic Acquisition in April 2012. The Company was able to acquire Dynamic for less than the estimated fair value of its net assets due to their offshore location resulting in less bidding competition.

In connection with the March 2013 redemption of the Company's 9.875% Senior Notes due 2016 and 8.0% Senior Notes due 2018, the Company recognized a loss on extinguishment of debt of $82.0 million for the year ended December 31, 2013. The Company recognized a loss on extinguishment of debt of $3.1 million for the year ended December 31, 2012 in connection with the tender offer to repurchase the Company's Senior Floating Rate Notes due 2014 (the "Senior Floating Rate Notes") in August 2012 and recognized a loss on extinguishment of debt of $38.2 million for the year ended December 31, 2011 in connection with the tender offer to repurchase and the redemption of the 8.625% Senior Notes due 2015 in March 2011. The losses on extinguishment represent the premium paid to purchase the notes and the write off of the remaining unamortized debt issuance costs associated with the notes.

The Company reported income tax expense of $5.7 million for the year ended December 31, 2013, primarily related to federal alternative minimum tax ("AMT") associated with the tax year ended December 31, 2013. The Company recorded a current liability and a corresponding deferred tax asset each in the amount of approximately $3.8 million for the year ended December 31, 2013. As a result of recording this deferred tax asset, the Company increased its valuation allowance against its net deferred tax asset by approximately $3.8 million. Also included in the income tax expense for the year ended December 31, 2013, is $2.4 million of current state income tax, which is partially offset by a reduction to the liability associated with unrecognized tax benefits. Despite incurring federal AMT and state income tax, the Company's effective tax rate remains low as a result of having a valuation allowance on its net deferred tax asset. The Company reported an income tax benefit of $100.4 million for the year ended December 31, 2012. The benefit was primarily attributable to the release of a portion of the Company's valuation allowance against its net deferred tax asset during the period. A net deferred tax liability of $100.3 million recorded as a result of the Dynamic Acquisition reduced the Company's existing net deferred tax asset position, resulting in a corresponding reduction in the valuation allowance against the net deferred tax asset. During the year ended December 31, 2011, the Company completed its valuation of assets acquired and liabilities assumed related to the acquisition of Arena in order to finalize the purchase price allocation. In connection therewith, the Company recorded an additional net deferred tax liability of $7.0 million and released a corresponding portion of its previously recorded valuation allowance resulting in a deferred tax benefit. Also during 2011, the Company filed the final income tax returns for Arena and its subsidiaries resulting in a current tax provision of $0.7 million.

Net income attributable to noncontrolling interest represents the portion of net income attributable to third-party ownership in the Company's consolidated VIEs and subsidiaries. Net income attributable to noncontrolling interest decreased to $39.4 million for the year ended December 31, 2013 from $105.0 million in 2012 due primarily to the $71.7 million loss on the sale of the Permian Properties attributable to noncontrolling interest during the year ended December 31, 2013. Additionally, losses from changes in fair value recognized on the Royalty Trusts' derivative contracts in the 2013 period compared to gains from changes in fair value in the 2012 period decreased net income in 2013. These decreases were partially offset by the inclusion of a full year of operating income for 2013 from the Mississippian Trust II, which completed its initial public offering in April 2012, compared to the inclusion of eight months of operating income in 2012. Net income attributable to noncontrolling interest increased to $105.0 million for the year ended December 31, 2012 from $54.3 million in 2011, due primarily to the completion of the Mississippian Trust I, Permian Trust and Mississippian Trust II initial public offerings in April 2011, August 2011 and April 2012, respectively.

Liquidity and Capital Resources

The Company's primary sources of liquidity and capital resources are cash on hand, cash flows from operating activities, proceeds from monetizations of assets, borrowings under the senior credit facility, funding commitments from third parties for drilling carries and the issuance of equity and debt securities in the capital markets. As described in Item 1 "Business—2013 Divestiture," the Company received proceeds of approximately $2.6 billion, including certain post-closing adjustments that were finalized in the third quarter of 2013, for the sale of its Permian Properties in

February 2013. Additionally, and as described in Item 1 “Business —2014 Divestiture,” the Company received proceeds of approximately $750.0 million, subject to post-closing adjustments, for the sale of its Gulf Properties in February 2014.

The Company’s primary uses of capital are expenditures related to its oil and natural gas properties, such as costs related to the drilling and completion of wells, including to fulfill its drilling commitments to the Permian Trust and Mississippian Trust II, the acquisition of oil and natural gas properties and other fixed assets, the payment of dividends on its outstanding convertible perpetual preferred stock, interest payments on its outstanding debt and, from time to time, the repayment of long-term debt. The Company maintains access to funds that may be needed to meet capital funding requirements through its senior credit facility.

The Company’s 2014 budget for capital expenditures, including expenditures related to the Company’s drilling programs for the Permian Trust and Mississippian Trust II and net of $205.6 million in drilling carries estimated to be received in 2014, is approximately $1.5 billion. The Company expects to fund its near term capital and debt service requirements and working capital needs with cash on hand ($814.7 million at December 31, 2013), cash flow from operations, proceeds from the sale of the Gulf Properties in 2014 and available borrowing capacity under its $775.0 million senior credit facility, which is undrawn, other than

$29.1 million in letters of credit secured by the senior credit facility that reduce availability on a dollar for dollar basis, at December 31, 2013. The Company has no maturities of long-term debt prior to 2020, and may choose to issue new long-term debt, subject to market availability, as an alternative to borrowing under its senior credit facility. Alternatively, the Company may issue equity or other non-debt securities in the capital markets, depending on market conditions, to address its funding requirements. In the longer term, the Company expects an increasing portion of its funding needs to be covered by increased cash flows from operations, resulting from its drilling program combined with recently implemented cost cutting initiatives, and may issue long-term debt or equity or monetize non-core assets to cover any difference between cash flow from operations and capital needs. Further, the majority of the Company's capital expenditures is discretionary and could be curtailed if the Company's cash flows decline from expected levels.

The Company and one of its wholly owned subsidiaries are parties to development agreements with the Permian Trust and Mississippian Trust II that obligate the Company to drill, or cause to be drilled, a specified number of wells within specific areas of mutual interest for each Royalty Trust by March 31, 2016 and December 31, 2016, respectively. The Company fulfilled its drilling obligation to the Mississippian Trust I during the second quarter of 2013. In addition, production targets contained in certain gathering and treating arrangements require the Company to incur capital expenditures or make associated shortfall payments. See additional discussion of these commitments under "Contractual Obligations and Off-Balance Sheet Arrangements."

A substantial or extended decline in oil or natural gas prices could have a material adverse effect on the Company's financial position, results of operations, cash flows and quantities of oil, natural gas and NGL reserves that may be economically produced, which could adversely impact the Company's ability to comply with the financial covenants under its senior credit facility, which in turn would limit borrowings to fund capital expenditures. The Company may increase or decrease planned capital expenditures depending on oil and natural gas prices and the availability of funding from the sources described above.

The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, each of which depend on numerous factors beyond the Company's control such as overall oil and natural gas production and inventories in relevant markets, economic conditions, the global political environment, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile and may be subject to significant fluctuations in the future. The Company's derivative arrangements serve to mitigate a portion of the effect of this price volatility on its cash flows, and while fixed price swap contracts are in place for the majority of expected oil production for 2014, fixed price swap contracts are in place for only a portion of expected oil production for 2015. No fixed price swap contracts are in place for any of the Company's future oil or natural gas production beyond 2015.

The Company may from time to time seek to retire or purchase its outstanding debt securities through cash purchases and/or exchanges in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions and other factors.

As of December 31, 2013, the Company's cash and cash equivalents were $814.7 million, including $8.0 million attributable to the Company's consolidated VIEs which is available to satisfy only obligations of the VIEs. The Company had approximately $3.2 billion in total debt outstanding and $29.1 million in outstanding letters of credit with no amount outstanding under its senior credit facility at December 31, 2013. As of and for the year ended December 31, 2013, the Company was in compliance with applicable covenants under its senior credit facility and outstanding senior fixed rate notes (the, "Senior Fixed Rate Notes"). As of February 25, 2014, the Company's cash and cash equivalents were approximately $1.4 billion, including $76.4 million attributable to the Company's consolidated VIEs. Additionally, there was no amount outstanding under the Company's senior credit facility and $30.0 million in outstanding letters of credit.

Working Capital

The Company’s working capital balance fluctuates as a result of changes in the fair value of its outstanding commodity derivative instruments and due to fluctuations in the timing and amount of its collection of receivables and payment of expenditures related to its exploration and production operations. Absent any significant effects from its commodity derivative instruments, the Company historically has maintained a working capital deficit or a relatively small amount of positive working capital because the Company’s capital spending generally has exceeded the Company’s cash flows from operations.

At December 31, 2013, the Company had a working capital surplus of $308.0 million compared to a deficit of $27.6 million at December 31, 2012. Current assets and current liabilities at December 31, 2012 each included a $255.0 million escrow deposit received in conjunction with the agreement to sell the Permian Properties. This deposit had no impact on working capital at December 31, 2012. Excluding the change in current assets attributable to the escrow deposit, current assets increased $353.9 million at December 31, 2013, compared to current assets at December 31, 2012, primarily due to a $504.9 million increase in cash and cash equivalents. The increase in cash and cash equivalents largely resulted from the receipt of net proceeds from the sale of the Permian Properties in February 2013 after funding the March 2013 redemption of the 9.875% Senior Notes due 2016 and 8.0% Senior Notes due 2018. This increase was partially offset by a $96.3 million decrease in accounts receivable and amounts due from working interest partners as a result of a decrease in drilling activity in areas where third-party working interests in properties were higher due to the sale of the Permian Properties, and a decrease of $58.2 million in the Company's asset position on its current derivative contracts due to an increase in oil prices compared to December 31, 2012. Excluding the escrow deposit, current liabilities increased $18.4 million at December 31, 2013, compared to current liabilities at December 31, 2012. The increase was primarily due to a $45.9 million increase in accounts payable and accrued expenses as a result of increased drilling activity in the Mid-Continent and costs associated with the Gulf Properties in 2012, and a $19.4 million increase in the net liability position of the Company's current derivative contracts primarily as a result of an increase in oil prices compared to December 31, 2012. These increases were partially offset by a $31.4 million decrease in the Company's current asset retirement obligations primarily due to Gulf of Mexico plugging and abandonment obligations settled during 2013 and a $15.5 million decrease in billings and contract loss in excess of costs incurred.

Cash Flows

The Company's cash flows for the years ended December 31, 2013, 2012 and 2011 are presented in the following table and discussed below:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Cash flows provided by operating activities	$868,630	$783,160	$458,954
Cash flows provided by (used in) investing activities	1,070,356	(2,555,945)	(902,329)
Cash flows (used in) provided by financing activities	(1,434,089)	1,874,870	645,193
Net increase in cash and cash equivalents	$504,897	$102,085	$201,818

Cash Flows from Operating Activities

The Company's operating cash flow is primarily influenced by the prices the Company receives for its oil, natural gas and NGL production, the quantity of oil, natural gas and NGLs it produces, settlements of derivative contracts, and third-party demand for its drilling rigs and oil field services and the rates it is able to charge for these services. Our cash flows from operating activities are also impacted by changes in working capital.

Net cash provided by operating activities for the year ended December 31, 2013 increased compared to 2012 due in part to an increase in prices received for oil and natural gas production. Also contributing to the increase were changes in operating assets and liabilities during 2013, primarily related to the timing of cash receipts and disbursements. These changes included a decrease in accounts receivable and a decrease in costs in billings and contract loss in excess of costs incurred, which were partially offset by an increase in cash paid to settle the Company's plugging and abandonment obligations, primarily on Gulf of Mexico properties acquired during the second quarter of 2012.

Net cash provided by operating activities for the year ended December 31, 2012 increased compared to 2011 due primarily to an increase in oil, natural gas and NGL sales as a result of increased oil, natural gas and NGL production, including production from properties located in the Gulf of Mexico that were acquired during the second quarter of 2012, and prices received for oil production and an increase in realized gains on the Company's commodity derivative contracts, partially offset by an increase in related operating costs.

Cash Flows from Investing Activities

The Company dedicates and expects to continue to dedicate a substantial portion of its capital expenditure program toward the exploration for and production of oil and natural gas. These capital expenditures are necessary to offset inherent declines in production and proven reserves, which is typical in the capital-intensive oil and natural gas industry.

Cash flows provided by investing activities were $1.1 billion for the year ended December 31, 2013 compared to cash flows used by investing activities of $2.6 billion for the year ended December 31, 2012. The change was due primarily to proceeds received from the sale of the Permian Properties and a decrease in capital expenditures and acquisitions for the year ended December 31, 2013. Proceeds from the sale of assets totaled $2.6 billion in the year ended December 31, 2013 compared to $431.2 million in the same period in 2012. See additional information on capital expenditures below.

Cash flows used in investing activities increased in the year ended December 31, 2012 from 2011 due to the acquisitions of oil and natural gas properties located in the Gulf of Mexico during the second quarter of 2012, and an increase in capital expenditures as a result of the continued development of the Company’s oil properties, primarily in the Mid-Continent. These amounts were partially offset by proceeds from the sale of assets during the year ended December 31, 2012. In 2012, the Company sold working interests to Repsol E&P USA, Inc. and its tertiary recovery properties for combined proceeds of $431.2 million compared to proceeds from the sale of assets in 2011 totaling $859.4 million, primarily from the sale of oil and natural gas properties and working interests to Atinum MidCon I, LLC.

Capital Expenditures. The Company’s capital expenditures, on an accrual basis, by segment for the years ended December 31, 2013, 2012 and 2011 are summarized below:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Capital expenditures			
Exploration and production	$1,319,012	$1,951,490	$1,697,691
Drilling and oil field services	7,125	27,527	25,674
Midstream services	55,706	80,413	38,514
Other	42,040	114,552	54,615
Capital expenditures, excluding acquisitions	1,423,883	2,173,982	1,816,494
Acquisitions	17,028	840,740	34,628
Total	$1,440,911	$3,014,722	$1,851,122

Capital expenditures, excluding acquisitions, decreased for the year ended December 31, 2013 compared to 2012, primarily as a result of an increased focus on capital discipline by the Company’s management. Capital expenditures, excluding acquisitions, increased for the year ended December 31, 2012 compared to 2011, primarily as a result of the continued development of the Company’s oil properties, primarily in the Mid-Continent. Additionally, capital expenditures related to acquisitions increased for the year ended December 31, 2012 as a result of the Dynamic Acquisition in April 2012 and the acquisition of other Gulf of Mexico properties in June 2012.

During the years ended December 31, 2013 and 2012, the Company received approximately $408.0 million and $367.6 million, respectively, relating to Atinum MidCon I, LLC and Repsol E&P USA, Inc.’s drilling carries, which directly offset the Company’s capital expenditures for the respective periods. As of December 31, 2013, Atinum MidCon I, LLC had fully funded its drilling carry commitment and the Company expects the remaining drilling carry for Repsol E&P USA Inc., of $205.6 million at December 31, 2013, to be fully funded during 2014 such that no drilling carry amounts will remain at December 31, 2014.

Cash Flows from Financing Activities

The Company’s financing activities used $1.4 billion in cash for the year ended December 31, 2013 compared to providing $1.9 billion of cash in the same period in 2012. Cash used in financing activities during the 2013 period was primarily comprised of the redemption of $1.1 billion aggregate principal amount of the 9.875% Senior Notes due 2016 and 8.0% Senior Notes due 2018 as well as the premium paid of $62.0 million in connection with the redemption of these notes, $206.5 million in distributions to third-party Royalty Trust unitholders, $55.5 million in dividends paid on the Company’s convertible perpetual preferred stock and $33.0 million in purchases of treasury stock as a result of shares of restricted stock that were traded for taxes.

The Company’s financing activities provided $1.9 billion in cash for the year ended December 31, 2012 compared to $645.2 million for the same period in 2011. Cash provided by financing activities during the 2012 period was primarily comprised of net proceeds of $1.1 billion from the issuance of the 7.5% Senior Notes due 2023 and additional 7.5% Senior Notes due 2021, net proceeds of $730.1 million from the issuance of the 8.125% Senior Notes due 2022, $587.1 million from the issuance of common units by the Mississippian Trust II and $139.4 million of proceeds from the sale of Mississippian Trust I and Permian Trust common units owned by the Company. These proceeds were offset by the $350.0 million purchase and redemption of the Senior Floating Rate Notes, $181.7 million in distributions to third-party Royalty Trust unitholders, $55.5 million in dividends paid on the Company's convertible perpetual preferred stock and $34.5 million in payments to settle financing derivatives.

Cash provided by financing activities during 2011 was primarily comprised of $880.6 million of net proceeds from the issuance of the 7.5% Senior Notes due 2021 and $917.5 million of net proceeds from the issuance of common units by the Mississippian Trust I and Permian Trust. These amounts were partially offset by the purchase and redemption of $650.0 million aggregate principal amount of the 8.625 % Senior Notes due 2015, as well as the premium paid of $30.3 million in connection with the purchase and redemption of the 8.625% due 2015, $340.0 million of net repayments under the senior credit facility, $60.2 million of noncontrolling interest distributions and $56.7 million of dividends paid on the Company's convertible perpetual preferred stock.

Indebtedness

Long-term debt consists of the following at December 31, 2013 (in thousands):

8.75% Senior Notes due 2020, net of $5,264 discount	$444,736
7.5% Senior Notes due 2021, including premium of $3,922	1,178,922
8.125% Senior Notes due 2022	750,000
7.5% Senior Notes due 2023, net of $3,751 discount	821,249
Total debt	$3,194,907

The indentures governing the senior notes contain covenants imposing certain restrictions on the Company's activities, including, but not limited to, limitations on the incurrence of indebtedness, payment of dividends, investments, asset sales, certain asset purchases, transactions with related parties and consolidations or mergers. As of and during the year ended December 31, 2013, the Company was in compliance with all of the covenants contained in the indentures governing its outstanding Senior Fixed Rate Notes.

Senior Credit Facility. The amount the Company may borrow under its senior credit facility is limited to a borrowing base, and is subject to periodic redeterminations. The Company's borrowing base is generally redetermined in April and October of each year, and was reaffirmed at $775.0 million in October 2013. The next redetermination will take place in April 2014. Quarterly, the Company pays a commitment fee assessed at an annual rate of 0.5% on any available portion of the senior credit facility. The borrowing base is determined based upon the discounted present value of future cash flows attributable to the Company's proved reserves. Because the value of the Company's proved reserves is a key factor in determining the amount of the borrowing base, changing commodity prices and the Company's success in developing reserves may affect the borrowing base.

At December 31, 2013, the Company had no amount outstanding under the senior credit facility and $29.1 million in outstanding letters of credit, which reduced the availability under the senior credit facility to $745.9 million at December 31, 2013. As of and during the year ended December 31, 2013, the Company was in compliance with all applicable financial covenants under the senior credit facility.

Redemption of Senior Notes. In March 2013, the Company redeemed $365.5 million aggregate principal amount of its 9.875% Senior Notes due 2016 and $750.0 million aggregate principal amount of its 8.0% Senior Notes due 2018 for total consideration of $1,061.34 per $1,000 principal amount and $1,052.77 per $1,000 principal amount, respectively. The premium paid to redeem these notes and the expense incurred to write off the remaining associated unamortized debt issuance costs resulted in a loss on extinguishment of debt of $82.0 million for the year ended December 31, 2013. The redemption was funded by a portion of the proceeds received from the sale of the Permian Properties. As a result of these redemptions in March 2013, the Company was no longer obligated for future interest payments totaling $423.6 million on these senior notes.

For more information about the senior credit facility and Senior Fixed Rate Notes, see "Note 12—Long-Term Debt" to the Company's consolidated financial statements in Item 8 of this report. For information on the future maturities of the Company's long-term debt, see the table below under "Contractual Obligations and Off-Balance Sheet Arrangements."

Contractual Obligations and Off-Balance Sheet Arrangements

As of December 31, 2013, the Company had future contractual payment commitments under various agreements which are not recorded in the accompanying consolidated balance sheets.

A summary of the Company's contractual obligations as of December 31, 2013 is provided in the following table (in thousands):

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Long-term debt obligations(1)	$5,173,389	$250,313	$500,625	$500,625	$3,921,826
Gas gathering agreement(2)	311,523	42,542	84,606	83,816	100,559
Transportation and throughput agreements	68,507	19,947	23,140	22,630	2,790
Third-party drilling rig agreements(3)	21,389	20,256	1,133	—	—
Asset retirement obligations	424,117	87,063	86,260	65,034	185,760
Operating leases and other(4)	49,835	8,552	10,042	3,433	27,808
Total	$6,048,760	$428,673	$705,806	$675,538	$4,238,743

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(1) Includes interest on long-term debt.

(2) Consists of a gas gathering agreement to deliver certain minimum volumes of natural gas to PGC, an unconsolidated variable interest entity. Pursuant to the agreement, the base fee for gathering services can be reduced if certain criteria are met. The amounts above are based on the base fee per the agreement.

(3) Includes drilling contracts with third-party drilling rig operators at specified day or footage rates and termination fees associated with the Company's hydraulic fracturing services agreements. All of the Company's drilling rig contracts contain operator performance conditions that allow for pricing adjustments or early termination for operator nonperformance.

(4) Includes the Company's obligation for the employee and employer match contributions to the participants of its non-qualified deferred compensation plan for eligible highly compensated employees who elect to defer income exceeding the IRS annual limitations on qualified 401(k) retirement plans.

In addition to the contractual obligations included in the table above, the Company has a development agreement with each of the Permian Trust and Mississippian Trust II and a treating agreement commitment with Occidental, the future effects of which are not reflected in its consolidated balance sheet at December 31, 2013, and are described below.

Development Agreements with Royalty Trusts. The Company's development agreements with the Permian Trust and Mississippian Trust II obligate the Company to drill, or cause to be drilled, a specified number of wells within an area of mutual interest for each trust by March 31, 2016 and December 31, 2016, respectively. The Company fulfilled its drilling obligation to the Mississippian Trust I during the second quarter of 2013. The estimated cost to fulfill the drilling obligations remaining at December 31, 2013 totaled approximately $137.0 million.

Treating Agreement Commitment. Under an agreement with Occidental, the Company is required to deliver a total of approximately 3,200 Bcf of CO_2 during the agreement period, which ends in 2042. At December 31, 2013, approximately 3,000 Bcf of CO_2 remained to be delivered. The Company is obligated to pay Occidental $0.25 per Mcf to the extent minimum annual CO_2 volume requirements are not met. Additionally, if CO_2 volumes delivered by the Company over the term of the agreement do not reach 3,200 Bcf, the Company is obligated to pay Occidental $0.70 per Mcf for such undelivered CO_2 volumes at the end of the agreement term in 2042. Based upon natural gas production levels in 2013, the Company accrued $32.7 million for amounts related to the Company's shortfall in meeting its 2013 annual delivery obligations, which was included in production expenses for the year ended December 31, 2013. Based on current projected natural gas production levels, the Company expects to accrue between approximately $30.0 million and $37.0 million during the year ending December 31, 2014 for amounts related to the Company's anticipated shortfall in meeting its 2014 annual delivery obligations. Due to the sensitivity of drilling activity to market prices for natural gas, the Company is unable to estimate additional amounts it may be required to pay under the agreement in subsequent periods; however, if natural gas prices remain low, drilling activity will likely remain very limited, which would result in additional shortfall payments in future periods.

Valuation Allowance

In 2008 and 2009, the Company recorded full cost ceiling impairments totaling $3.5 billion on its oil and natural gas assets, resulting in the Company being in a net deferred tax asset position. Management considered all available evidence and concluded that it was more likely than not that some or all of the deferred tax assets would not be realized and established a valuation allowance against the Company’s net deferred tax asset in the period ending December 31, 2008. This valuation allowance has been maintained since 2008. See “Note 18—Income Taxes” to the Company’s consolidated financial statements in Item 8 of this report for more discussion on the establishment of the valuation allowance against the Company’s net deferred tax asset.

Management continues to closely monitor all available evidence in considering whether to maintain a valuation allowance on its net deferred tax asset. Factors considered are, but not limited to, the reversal periods of existing deferred tax liabilities and deferred tax assets, the historical earnings of the Company and the prospects of future earnings. For purposes of the valuation allowance analysis, “earnings” is defined as pre-tax earnings as adjusted for permanent tax adjustments.

The Company was in a cumulative negative earnings position until the 36-month period ended December 31, 2012 at which time it reached cumulative positive earnings. However, as a result of the Company closing the sale of the Permian Properties on February 26, 2013, the Company reverted back to a cumulative negative earnings position for the 36-month period ended March 31, 2013. See “Note 3 - Acquisitions and Divestitures” to the Company’s consolidated financial statements in Item 8 of this report for discussion of the sale of the Permian Properties. Based on net book value, historical costs and proved reserves as of February 26, 2013, the Company recorded a loss on the sale of $398.9 million, which caused the Company to report a loss for the quarter ended March 31, 2013. The Company remains in a cumulative negative earnings position through the 36-month period ended December 31, 2013. The resulting cumulative negative earnings are not a definitive factor in determining to maintain a valuation allowance as all available evidence should be considered, but it is a significant piece of negative evidence in management’s analysis.

In recent years, the Company has experienced significant earnings volatility due to substantial changes in the market price of natural gas. In 2008, the Company’s earnings were primarily derived from natural gas sales and during 2008 the market price of natural gas began a steep decline. Since 2008, natural gas prices have remained relatively low, although there has been a slight upward trend since early 2012. As a result of a shift in strategy, the Company’s revenues are now primarily derived from oil, the price of which has experienced a greater recovery since 2008 than that of natural gas. The Company continues to take additional steps to further ensure stockholder value and future profitability.

The Company’s revenue, profitability and future growth are substantially dependent upon prevailing and future prices for oil and natural gas. The markets for these commodities continue to be volatile. Relatively modest drops in prices can significantly affect the Company’s financial results and impede its growth. Changes in oil and natural gas prices have a significant impact on the value of the Company’s reserves and on its cash flow. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas and a variety of additional factors that are beyond the Company’s control. Due to these factors, management has placed a lower weight on the prospects of future earnings in its overall analysis of the valuation allowance.

In determining whether to maintain the valuation allowance, management concluded that the objectively verifiable negative evidence of cumulative negative earnings for the 36-month period ending December 31, 2013, is difficult to overcome with any forms of positive evidence that may exist. Accordingly, management has not changed its judgment regarding the need for a full valuation allowance against its net deferred tax asset. The valuation allowance against the Company’s net deferred tax asset at December 31, 2013 was $702.7 million.

Additionally, at December 31, 2013, the Company has valuation allowances totaling $50.8 million against specific deferred tax assets for which management has determined it is more likely than not that such deferred tax assets will not be realized for various reasons. The valuation allowance against these specific deferred tax assets would not be impacted by the foregoing discussion.

Critical Accounting Policies and Estimates

The discussion and analysis of the Company’s financial condition and results of operations are based upon the Company’s consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of the Company’s financial statements requires the Company to make assumptions and prepare estimates that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. The Company bases its estimates on historical experience and various other assumptions that the Company believes are reasonable; however, actual results may differ significantly. Estimates of oil, natural gas and NGL reserves and their values, future production rates and future costs and expenses are inherently uncertain for numerous reasons, including many factors beyond the Company's control. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, prevailing commodity prices, operating costs and other factors. These revisions may be material and could materially affect the Company's future depletion, depreciation and amortization expenses. The Company's critical accounting policies and additional information on significant estimates used by the Company are discussed below. See "Note 1—Summary of Significant Accounting Policies" to the Company's consolidated financial statements in Item 8 of this report for additional discussion of the Company's significant accounting policies.

Derivative Financial Instruments. To manage risks related to fluctuations in prices attributable to its expected oil and natural gas production, the Company enters into oil and natural gas derivative contracts. The Company may also, from time to time, enter into interest rate swaps in order to manage risk associated with its exposure to variable interest rates.

The Company recognizes its derivative instruments as either assets or liabilities at fair value with changes in fair value recognized in earnings unless designated as a hedging instrument with specific hedge accounting criteria having been met. The Company has elected not to designate price risk management activities as accounting hedges under applicable accounting guidance, and, accordingly, accounts for its commodity derivative contracts at fair value with changes in fair value reported currently in earnings. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract. The related cash flow impact of the Company's derivative activities are reflected as cash flows from operating activities unless the derivative contract contains a significant financing element, in which case, cash settlements are classified as cash flows from financing activities in the consolidated statement of cash flows.

Fair values of commodity derivative financial instruments are determined primarily by using discounted cash flow calculations or option pricing models, and are based upon inputs that are either readily available in the public market, such as oil and natural gas futures prices, volatility factors, interest rates and discount rates, or can be corroborated from active markets. Estimates of future prices are based upon published forward commodity price curves for oil and natural gas instruments. Valuations also incorporate adjustments for the nonperformance risk of the Company or its counterparties, as applicable.

Fair value of interest rate swap financial instruments is estimated primarily by using discounted cash flow calculations based upon forward interest rate yields, which is the most significant variable input. These estimates of future yields are based upon utilizing forward curves such as the London Interbank Offered Rate ("LIBOR") provided by third parties. Valuations also incorporate adjustments for the nonperformance risk of the Company or its counterparty, as applicable.

Proved Reserves. Approximately 86.1% of the Company's reserves were estimated by independent petroleum engineers for the year ended December 31, 2013. Estimates of proved reserves are based on the quantities of oil, natural gas and NGLs that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond the Company's control. Estimating reserves is a complex process and relies on assumptions and subjective interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, as a result of volatility and changing market conditions, commodity prices and future development costs will change from period to period, causing estimates of proved reserves to change, as well as causing estimates of future net revenues to change. For the years ended December 31, 2013, 2012 and 2011, the Company revised its proved reserves from prior years' reports by approximately (19.2) MMBoe, (112.0) MMBoe and (36.8) MMBoe, respectively, due to market prices during or at the end of the applicable period, production performance indicating more (or less) reserves in place, larger (or smaller) reservoir size than initially estimated or additional proved reserve bookings within the original field boundaries. Estimates of proved reserves are key components of the Company's most significant financial estimates used to determine depreciation and depletion on oil and natural gas properties and its full cost ceiling limitation. Future revisions to estimates of proved reserves may be material and could materially affect the Company's future depreciation and depletion expenses.

Method of Accounting for Oil and Natural Gas Properties. The Company's business is subject to accounting rules that are unique to the oil and natural gas industry. There are two allowable methods of accounting for oil and natural gas business activities: the successful efforts method and the full cost method. The Company uses the full cost method to account for its oil and natural gas properties. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Exploration and development costs include dry well costs, geological and geophysical costs, direct overhead related to exploration and development activities and other costs incurred for the purpose of finding oil, natural gas and NGL reserves. Amortization of oil and natural gas properties is calculated using the unit-of-production method based on estimated proved oil, natural gas and NGL reserves. Sales and abandonments of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil, natural gas and NGL reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of a cost center.

Under the successful efforts method, geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred. Costs of drilling exploratory wells that do not result in proved reserves are charged to expense. Depreciation, depletion and impairment of oil and natural gas properties are generally calculated on a well by well, lease or field basis versus the aggregated “full cost” pool basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties under the successful efforts method. As a result, the Company’s financial statements will differ from companies that apply the successful efforts method since the Company will generally reflect a higher level of capitalized costs as well as a higher oil and natural gas depreciation and depletion rate, and the Company will not have exploration expenses that successful efforts companies frequently have.

Impairment of Oil and Natural Gas Properties. In accordance with full cost accounting rules, capitalized costs are subject to a limitation. The capitalized cost of oil and natural gas properties, net of accumulated depreciation, depletion and impairment, less related deferred income taxes, may not exceed an amount equal to the present value of future net revenues from proved oil, natural gas and NGL reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less related tax effects (the “ceiling limitation”). The Company calculates its full cost ceiling limitation using the 12-month average oil and natural gas prices for the most recent 12 months as of the balance sheet date and adjusted for basis or location differential, held constant over the life of the reserves. If capitalized costs exceed the ceiling limitation, the excess must be charged to expense. Once incurred, a write-down is not reversible at a later date. There were no full cost ceiling impairments recorded during the years ended December 31, 2013, 2012 or 2011.

Unproved Properties. The balance of unproved properties consists primarily of costs to acquire unproved acreage. These costs are initially excluded from the Company’s amortization base until it is known whether proved reserves will or will not be assigned to the property. The Company assesses all properties, on an individual basis or as a group if properties are individually insignificant, classified as unproved on a quarterly basis for possible impairment or reduction in value. The assessment includes consideration of various factors, including, but not limited to, the following: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis. The Company estimates that substantially all of its costs classified as unproved as of the balance sheet date will be evaluated and transferred within a 10-year period from the date of acquisition, contingent on the Company’s capital expenditures and drilling program.

Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and treating equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of such property and equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 10 to 39 years for buildings and 3 to 30 years for equipment. When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed and any resulting gain or loss is reflected in operations. Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying value of such asset or asset group may not be recoverable. Assets are considered to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset or asset group including disposal value if any, is less than the carrying amount of the asset or asset group. If an asset or asset group is determined to be impaired, the impairment loss is measured as the amount by which the carrying amount of the asset or asset group exceeds its fair value. An estimate of fair value is based on the best information available, including prices for similar assets. Changes in such estimates could cause the Company to reduce the carrying value of property and equipment.

See "Note 8—Impairment" to the Company's consolidated financial statements in Item 8 of this report for a discussion of the Company's impairments.

Goodwill. In conjunction with its acquisition of Arena, the Company recorded goodwill equal to the excess of the consideration paid over the fair value of identifiable net assets acquired. In December 2012, the Company entered into an agreement to sell the Permian Properties, which the Company determined to be a triggering event to evaluate goodwill for impairment. As such, an impairment test was performed as of December 31, 2012. Primarily as a result of a decrease in the Company's probable reserves as of December 31, 2012, which is one of the significant components in the determination of the fair value of the reporting unit, the carrying value of the reporting unit exceeded the fair value. Probable reserves used in the reporting unit fair value calculation decreased due to their reclassification to possible reserves as a result of the Company’s year- end evaluation of drilling results across its acreage in the Mississippian formation. Possible reserves are not included in the fair value calculation of the reporting unit. The Company performed step two of the impairment test which indicated the carrying value of goodwill was fully impaired. As a result, the Company recorded an impairment of the full carrying amount of goodwill of $235.4 million at December 31, 2012.

Asset Retirement Obligations. Asset retirement obligations represent the estimate of fair value of the cost to plug, abandon and remediate the Company’s wells at the end of their productive lives, in accordance with applicable federal and state laws. The Company estimates the fair value of an asset’s retirement obligation in the period in which the liability is incurred, if a reasonable estimate can be made. Estimating future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability and what constitutes adequate restoration. The Company employs a present value technique to estimate the fair value of an asset retirement obligation, which reflects certain assumptions and requires significant judgment, including an inflation rate, its credit-adjusted, risk-free interest rate, the estimated settlement date of the liability and the estimated current cost to settle the liability based on third-party quotes and current actual costs. Inherent in the present value calculation rates are the timing of settlement and changes in the legal, regulatory, environmental and political environments, which are subject to change. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Revenue Recognition and Natural Gas Balancing. Oil, natural gas and NGL revenues are recorded when title of production sold passes to the customer, net of royalties, discounts and allowances, as applicable. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are presented separately from such revenues and included in production tax expense in the consolidated statement of operations.

The Company accounts for natural gas production imbalances using the sales method, whereby it recognizes revenue on all natural gas sold to its customers notwithstanding the fact that its ownership may be less than 100% of the natural gas sold. Liabilities are recorded for imbalances greater than the Company’s proportionate share of remaining estimated natural gas reserves.

The Company accounted for its two construction contracts, discussed in “Note 11—Construction Contracts” to the Company’s consolidated financial statements in Item 8 of this report, using the completed-contract method, under which contract revenues and costs are recognized when work under the contract is completed or substantially completed and assets have been transferred. In the interim, costs incurred on and billings related to contracts in process are accumulated on the balance sheet. Contract losses are recorded at the time it is determined that a loss will be incurred. The contract loss on the Century Plant construction contract was recorded as a development cost within the Company’s oil and natural gas properties as part of the full cost pool. Contract gains, if any, are recorded upon substantial completion of the construction project.

The Company recognizes revenues and expenses generated from daywork and footage drilling contracts as the services are performed as the Company does not bear the risk of completion of the well. The Company may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one location to another are recognized at the time mobilization services are performed.

In general, natural gas purchased and sold by the midstream business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Revenues are recognized upon delivery of natural gas to customers and/or when services are rendered, pricing is determined and collectability is reasonably assured. Revenues from third-party midstream services are presented on a gross basis, since the Company acts as a principal by taking ownership of the natural gas purchased and taking responsibility of fulfillment for natural gas volumes sold.

Income Taxes. Deferred income taxes are recorded for temporary differences between financial statement and income tax basis. Temporary differences are differences between the amounts of assets and liabilities reported for financial statement purposes and their tax basis. Deferred tax assets are recognized for temporary differences that will be deductible in future years' tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years' tax returns. As of December 31, 2013, the Company continued to have a full valuation allowance against its net deferred tax asset. The valuation allowance serves to reduce the tax benefits recognized from the net deferred tax asset to an amount that is more likely than not to be realized based on the weight of all available evidence.

Variable Interest Entities. An entity is referred to as a VIE if it possesses one of the following criteria: (i) it is thinly capitalized, (ii) the residual equity holders do not control the entity, (iii) the equity holders are shielded from the economic losses, (iv) the equity holders do not participate fully in the entity's residual economics, or (v) the entity was established with nonsubstantive voting interests. The Company consolidates a VIE when it has determined it is the primary beneficiary, which requires significant judgment. The primary beneficiary of a VIE is that variable interest holder possessing a controlling financial interest through (i) its power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) its obligation to absorb losses or its right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether the Company owns a variable interest in a VIE and the significance of the variable interest, the Company performs a qualitative analysis of the entity's design, organizational structure, primary decision makers and related financial agreements. In addition to the VIEs that the Company consolidates, the Company also holds a variable interest in another VIE that is not consolidated as it was determined that the Company is not the primary beneficiary. The Company monitors both consolidated and unconsolidated VIEs to determine if any events have occurred that could cause the primary beneficiary to change. See "Note 4—Variable Interest Entities" to the Company's consolidated financial statements in Item 8 of this report for a discussion of the Company's VIEs.

Allocation of Purchase Price in Business Combinations. Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities. Any excess of the purchase price over the amounts assigned to assets and liabilities is recorded as goodwill.

The purchase price allocation is accomplished by recording each asset and liability at its estimated fair value. Estimated deferred taxes are based on available information concerning the tax basis of the acquired company's assets and liabilities and tax-related carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed relative to the total acquisition cost.

In estimating the fair values of assets acquired and liabilities assumed, the Company makes various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and natural gas properties. To estimate the fair values of these properties, the Company prepares estimates of oil, natural gas and NGL reserves and applies a discount for reserve categories based on industry factors applicable to each acquisition. The prices utilized in the reserves estimates are based upon forward commodity strip prices. Future cash flows are discounted using an industry weighted average cost of capital rate. Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. See "Note 3—Acquisitions and Divestitures" to the Company's consolidated financial statements in Item 8 of this report for a discussion of the Company's acquisitions.

New Accounting Pronouncements. For a discussion of recently adopted accounting standards and recent accounting standards not yet adopted, see "Note 1—Summary of Significant Accounting Policies" to the Company's consolidated financial statements in Item 8 of this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

General

This discussion provides information about the financial instruments the Company uses to manage commodity prices and interest rate volatility, including instruments used to manage commodity prices for production attributable to the Royalty Trusts. All contracts are settled in cash and do not require the actual delivery of a commodity at settlement.

Commodity Price Risk. The Company's most significant market risk relates to the prices it receives for its oil, natural gas and NGL production. Due to the historical price volatility of these commodities, the Company periodically has entered into, and expects in the future to enter into, derivative arrangements for the purpose of reducing the variability of oil and natural gas prices the Company receives for its production. From time to time, the Company enters into commodity pricing derivative contracts for a portion of its anticipated oil and natural gas production volumes depending upon management's view of opportunities under the then-prevailing current market conditions. The Company's senior credit facility limits its ability to enter into derivative transactions to 85% of expected production volumes from estimated proved reserves.

The Company uses, and may continue to use, a variety of commodity-based derivative contracts, including fixed price swaps, collars and basis swaps. At December 31, 2013, the Company's commodity derivative contracts consisted of fixed price swaps and collars, which are described below:

Fixed price swaps	The Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.
Collars	Two-way collars contain a fixed floor price (put) and a fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party. Three-way collars have two fixed floor prices (a purchased put and a sold put) and a fixed ceiling price (call). The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The call establishes a maximum price (ceiling) the Company will receive for the volumes under the contract.

The Company's oil fixed price swap transactions are settled based upon the average daily prices for the calendar month or quarter of the contract period. The Company's three-way oil collars are settled based upon the arithmetic average of NYMEX oil prices during the calculation period for the relevant contract. The Company's natural gas fixed price swap transactions are settled based upon the NYMEX prices on the final commodity business day for the relevant contract, and the Company's natural gas collars are settled based upon the NYMEX prices on the penultimate commodity business day for the relevant contract. Settlement for oil derivative contracts occurs in the succeeding month or quarter and natural gas derivative contracts are settled in the production month or quarter.

At December 31, 2013, the Company's open commodity derivative contracts consisted of the following:

Oil Price Swaps

	Notional (MBbls)	Weighted Average Fixed Price
January 2014 — December 2014	8,813	$92.98
January 2015 — December 2015	7,979	$86.13

Natural Gas Price Swaps

	Notional (MMcf)	Weighted Average Fixed Price
January 2014 — December 2014	35,490	$4.20

Oil Collars - Three-way

	Notional (MBbls)	Sold Put	Purchased Put	Sold Call
January 2014 — December 2014	8,213	$70.00	$90.20	$100.00
January 2015 — December 2015	2,920	$73.13	$90.82	$103.13

Natural Gas Collars

	Notional (MMcf)	Collar Range		
January 2014 — December 2014	937	$4.00	—	$7.78
January 2015 — December 2015	1,010	$4.00	—	$8.55

Because the Company has not designated any of its derivative contracts as hedges for accounting purposes, changes in fair values of the Company’s derivative contracts are recognized as gains and losses in current period earnings. As a result, the Company’s current period earnings may be significantly affected by changes in the fair value of its commodity derivative contracts. Changes in fair value are principally measured based on future prices as of period-end compared to the contract price.

The Company recorded loss (gain) on commodity derivative contracts of $47.1 million, $(241.4) million and $(44.1) million for the years ended December 31, 2013, 2012 and 2011, respectively, which includes net cash (receipts) payments upon contract settlement of $(3.2) million, $(100.7) million and $37.6 million, respectively. For the year ended December 31, 2013, $29.6 million of cash payments related to early settlements of commodity derivative contracts as a result of the sale of the Permian Properties. For the year ended December 31, 2012, the gain on commodity derivative contracts is net of a non-cash loss of $117.1 million resulting from the amendment of certain 2012 derivative contracts to contracts maturing in 2014 and 2015.

See “Note 13—Derivatives” to the Company’s consolidated financial statements in Item 8 of this report for additional information regarding the Company’s commodity derivatives.

Credit Risk. All of the Company’s derivative transactions have been carried out in the over-the-counter market. The use of derivative transactions in over-the-counter markets involves the risk that the counterparties may be unable to meet the financial terms of the transactions. The counterparties for all of the Company’s derivative transactions have an “investment grade” credit rating. The Company monitors on an ongoing basis the credit ratings of its derivative counterparties and considers its counterparties’ credit default risk ratings in determining the fair value of its derivative contracts. The Company’s derivative contracts are with multiple counterparties to minimize its exposure to any individual counterparty.

A default by the Company under its senior credit facility constitutes a default under its derivative contracts with counterparties that are lenders under the senior credit facility. The Company does not require collateral or other security from counterparties to support derivative instruments. The Company has master netting agreements with all of its derivative contract counterparties, which allow the Company to net its derivative assets and liabilities with the same counterparty. As a result of the netting provisions, the Company’s maximum amount of loss under derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the derivative contracts. The Company’s loss is further limited as any amounts due from a defaulting counterparty that is a lender under the senior credit facility can be offset against amounts owed, if any, to such counterparty under the Company’s senior credit facility. As of December 31, 2013, the majority of the Company’s open derivative contracts are with counterparties that share in the collateral supporting the Company’s senior credit facility. As a result, the Company is not required to post additional collateral under its derivative contracts. To secure their obligations under the derivative contracts novated by the Company, the Permian Trust and Mississippian Trust II have each given the counterparties to such contracts a lien on their royalty interests. See “Note 4—Variable Interest Entities” to the Company’s consolidated financial statements in Item 8 of this report for additional information on the Permian Trust’s and Mississippian Trust II’s derivative contracts.

The Company’s ability to fund its capital expenditure budget is partially dependent upon the availability of funds under its senior credit facility. In order to mitigate the credit risk associated with individual financial institutions committed to participate in the senior credit facility, the Company’s bank group currently consists of 23 financial institutions with commitments ranging from 1.00% to 6.00% of the borrowing base.

Interest Rate Risk. The Company is exposed to interest rate risk on its long-term fixed rate debt and will be exposed to variable interest rates if it draws on its senior credit facility. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes the Company to (i) changes in market interest rates reflected in the fair value of the debt and (ii) the risk that the Company may need to refinance maturing debt with new debt at a higher rate. Variable rate debt, where the interest rate fluctuates, exposes the Company to short-term changes in market interest rates as the Company’s interest obligations on these instruments are periodically redetermined based on prevailing market interest rates, primarily the LIBOR and the federal funds rate. The Company had no outstanding variable rate debt as of December 31, 2013.

Prior to its maturity on April 1, 2013, the Company had a $350.0 million notional interest rate swap agreement, which effectively fixed the variable interest rate on the Senior Floating Rate Notes at an annual rate of 6.69% for periods prior to their repurchase and redemption in the third quarter of 2012. The interest rate swap was not designated as a hedge.

The Company recorded a loss on its interest rate swaps of $0.01 million, $1.2 million and $3.2 million for the years ended December 31, 2013, 2012 and 2011, respectively, which is included in interest expense in the consolidated statements of operations. Included in the loss for the years ended December 31, 2013, 2012 and 2011 are cash payments upon contract settlement of $2.4 million, $9.2 million and $9.4 million, respectively.

Item 8. Financial Statements and Supplementary Data

The Company's consolidated financial statements required by this item are included in this report beginning on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures. Under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer, the Company performed an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures pursuant to Exchange Act Rules 13a-15 and 15d-15 as of the end of the period covered by this annual report. Based on that evaluation, the Company’s Chief Executive Officer and its Chief Financial Officer concluded that its disclosure controls and procedures were effective as of December 31, 2013 to provide reasonable assurance that the information required to be disclosed by the Company in its reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, or other persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Management’s Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm. The information required to be furnished pursuant to this item is set forth under the captions “Management’s Report on Internal Control over Financial Reporting” and “Report of Independent Registered Public Accounting Firm” in Item 8 of this report.

Changes in Internal Control over Financial Reporting. There were no changes in the Company’s internal control over financial reporting during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Item 9B. Other Information

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2014: "Director Biographical Information," "Executive Officers," "Compliance with Section 16(a) of the Exchange Act" and "Corporate Governance Matters."

Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2014: "Director Compensation," "Outstanding Equity Awards" and "Executive Officers and Compensation."

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2014: "Equity Compensation Plan Information" and "Security Ownership of Certain Beneficial Owners and Management."

Item 13. Certain Relationships and Related Transactions and Director Independence

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2014: "Related Party Transactions" and "Corporate Governance Matters."

Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the section captioned “Ratification of Selection of Independent Registered Public Accounting Firm” in the Company’s definitive proxy statement, which will be filed no later than April 30, 2014.

PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as a part of this report:

(1)Consolidated Financial Statements

Reference is made to the Index to Consolidated Financial Statements appearing on page F-1.

(2)Financial Statement Schedules

All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.

(3)Exhibits

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Based on our evaluation using criteria for effective internal control over financial reporting described in Internal Control—Integrated Framework (1992), our management concluded, that as of December 31, 2013, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

/s/ JAMES D. BENNETT	/s/ EDDIE M. LEBLANC
James D. Bennett	Eddie M. LeBlanc
President and Chief Executive Officer	Executive Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of SandRidge Energy, Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in stockholders' equity and cash flows present fairly, in all material respects, the financial position of SandRidge Energy, Inc. and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP

Tulsa, Oklahoma
February 28, 2014

SandRidge Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2013	2012
	(In thousands, except per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$814,663	$309,766
Accounts receivable, net	349,218	445,506
Derivative contracts	12,779	71,022
Costs in excess of billings and contract loss	4,079	11,229
Prepaid expenses	39,253	31,319
Restricted deposit	—	255,000
Other current assets	21,831	19,043
Total current assets	1,241,823	1,142,885
Oil and natural gas properties, using full cost method of accounting		
Proved (includes development and project costs excluded from amortization of $45.6 million and $72.4 million at December 31, 2013 and 2012, respectively)	10,972,816	12,262,921
Unproved	531,606	865,863
Less: accumulated depreciation, depletion and impairment	(5,762,969)	(5,231,182)
	5,741,453	7,897,602
Other property, plant and equipment, net	566,222	582,375
Derivative contracts	14,126	23,617
Other assets	121,171	144,252
Total assets	$7,684,795	$9,790,731

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

SandRidge Energy, Inc., and Subsidiaries
Consolidated Balance Sheets—Continued

	December 31, 2013	2012
	(In thousands, except per share data)	
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable and accrued expenses	$812,488	$766,544
Billings and contract loss in excess of costs incurred	—	15,546
Derivative contracts	34,267	14,860
Asset retirement obligations	87,063	118,504
Deposit on pending sale	—	255,000
Total current liabilities	933,818	1,170,454
Long-term debt	3,194,907	4,301,083
Derivative contracts	20,564	59,787
Asset retirement obligations	337,054	379,906
Other long-term obligations	22,825	17,046
Total liabilities	4,509,168	5,928,276
Commitments and contingencies (Note 15)		
Equity		
SandRidge Energy, Inc. stockholders' equity		
Preferred stock, $0.001 par value, 50,000 shares authorized		
8.5% Convertible perpetual preferred stock; 2,650 shares issued and outstanding at December 31, 2013 and 2012; aggregate liquidation preference of $265,000	3	3
6.0% Convertible perpetual preferred stock; 2,000 shares issued and outstanding at December 31, 2013 and 2012; aggregate liquidation preference of $200,000	2	2
7.0% Convertible perpetual preferred stock; 3,000 shares issued and outstanding at December 31, 2013 and 2012; aggregate liquidation preference of $300,000	3	3
Common stock, $0.001 par value, 800,000 shares authorized; 491,609 issued and 490,290 outstanding at December 31, 2013 and 491,578 issued and 490,359 outstanding at December 31, 2012	483	476
Additional paid-in capital	5,298,301	5,233,019
Additional paid-in capital—stockholder receivable	(3,750)	(5,000)
Treasury stock, at cost	(8,770)	(8,602)
Accumulated deficit	(3,460,462)	(2,851,048)
Total SandRidge Energy, Inc. stockholders' equity	1,825,810	2,368,853
Noncontrolling interest	1,349,817	1,493,602
Total equity	3,175,627	3,862,455
Total liabilities and equity	$7,684,795	$9,790,731

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

	Years Ended December 31,		
	2013	2012	2011
	(In thousands, except per share amounts)		
Revenues			
Oil, natural gas and NGL	$1,820,278	$1,759,282	$1,226,794
Drilling and services	66,586	116,633	103,298
Midstream and marketing	58,304	40,486	66,690
Construction contract	23,349	796,323	—
Other	14,871	18,241	18,431
Total revenues	1,983,388	2,730,965	1,415,213
Expenses			
Production	516,427	477,154	322,877
Production taxes	32,292	47,210	46,069
Cost of sales	57,118	68,227	65,654
Midstream and marketing	53,644	39,669	66,007
Construction contract	23,349	796,323	—
Depreciation and depletion—oil and natural gas	567,732	568,029	317,246
Depreciation and amortization—other	62,136	60,805	53,630
Accretion of asset retirement obligations	36,777	28,996	9,368
Impairment	26,280	316,004	2,825
General and administrative	207,920	241,682	148,643
Employee termination benefits	122,505	—	—
Loss (gain) on derivative contracts	47,123	(241,419)	(44,075)
Loss (gain) on sale of assets	399,086	3,089	(2,044)
Total expenses	2,152,389	2,405,769	986,200
(Loss) income from operations	(169,001)	325,196	429,013
Other income (expense)			
Interest expense	(270,234)	(303,349)	(237,332)
Bargain purchase gain	—	122,696	—
Loss on extinguishment of debt	(82,005)	(3,075)	(38,232)
Other income, net	12,445	4,741	3,122
Total other expense	(339,794)	(178,987)	(272,442)
(Loss) income before income taxes	(508,795)	146,209	156,571
Income tax expense (benefit)	5,684	(100,362)	(5,817)
Net (loss) income	(514,479)	246,571	162,388
Less: net income attributable to noncontrolling interest	39,410	105,000	54,323
Net (loss) income attributable to SandRidge Energy, Inc.	(553,889)	141,571	108,065
Preferred stock dividends	55,525	55,525	55,583
(Loss applicable) income available to SandRidge Energy, Inc. common stockholders	$(609,414)	$86,046	$52,482
(Loss) earnings per share			
Basic	$(1.27)	$0.19	$0.13
Diluted	$(1.27)	$0.19	$0.13
Weighted average number of common shares outstanding			
Basic	481,148	453,595	398,851
Diluted	481,148	456,015	406,645

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

SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Changes in Stockholders' Equity

	Convertible Perpetual Preferred Stock		Common Stock		Additional Paid-In Capital	Treasury Stock	Accumulated Deficit	Non-controlling Interest	Total
	Shares	Amount	Shares	Amount					
	(In thousands)								
Balance at December 31, 2010	7,650	$ 8	406,360	$ 398	$ 4,528,912	$ (3,547)	$ (2,989,576)	$ 11,288	$ 1,547,483
Issuance of units by royalty trusts	—	—	—	—	—	—	—	917,528	$ 917,528
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(60,200)	(60,200)
Issuance of convertible perpetual preferred stock, net	—	—	—	—	(231)	—	—	—	(231)
Purchase of treasury stock	—	—	—	—	—	(10,834)	—	—	(10,834)
Retirement of treasury stock	—	—	—	—	(10,834)	10,834	—	—	—
Stock purchase—retirement plans, net of distributions	—	—	(405)	—	3,179	(2,611)	—	—	568
Stock-based compensation	—	—	—	—	47,778	—	—	—	47,778
Stock-based compensation excess tax benefit	—	—	—	—	53	—	—	—	53
Issuance of restricted stock awards, net of cancellations	—	—	5,998	1	(1)	—	—	—	—
Net income	—	—	—	—	—	—	108,065	54,323	162,388
Convertible perpetual preferred stock dividends	—	—	—	—	—	—	(55,583)	—	(55,583)
Balance at December 31, 2011	7,650	8	411,953	399	4,568,856	(6,158)	(2,937,094)	922,939	2,548,950
Issuance of units by royalty trusts	—	—	—	—	—	—	—	587,086	587,086
Sale of royalty trust units	—	—	—	—	79,056	—	—	60,304	139,360
Distributions to noncontrolling interest owners	—	—	—	—	—				