SANDRIDGE ENERGY INC
Form 10-K
March 01, 2013
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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, 2012

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	20-8084793
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
123 Robert S. Kerr Avenue Oklahoma City, Oklahoma	73102
(Address of principal executive offices)	(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
Preferred Stock Purchase Rights	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 29, 2012 was approximately $3.0 billion based on the closing price as quoted on the New York Stock Exchange. As of February 22, 2013, there were 493,991,081 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company’s definitive proxy statement for the 2012 Annual Meeting of Stockholders are incorporated by reference in Part III.

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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 28.

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 express a belief, expectation or intention and generally are accompanied by words that convey projected future events or outcomes. These forward-looking statements may include projections and estimates concerning capital expenditures, the Company's liquidity, capital resources, and debt profile, pending acquisitions or 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, economic 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," "intend" or other words that convey the 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 and natural gas prices;
- uncertainties in estimating oil and natural gas reserves;
- the need to replace the oil and natural gas the Company produces;
- the Company's ability to execute its growth strategy by drilling wells as planned;
- risks and liabilities associated with acquired properties and risks related to the integration of acquired businesses;
- 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, Gulf of Mexico and west Texas;
- economic viability of certain natural gas production in west Texas due to high CO_2 content;
- availability of natural gas production for the Company's midstream services operations;
- limitations of seismic data;
- the potential adverse effect of commodity price declines on the carrying value of the Company's oil and natural gas properties;

- severe or unseasonable weather that may adversely affect production;
- availability of satisfactory oil and natural gas marketing and transportation;
- availability and terms of capital to fund capital expenditures;
- amount and timing of proceeds of asset sales and 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;

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- risks associated with consent solicitations and proxy contests conducted by dissident stockholders;
- 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.

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PART I

Item 1. Business

GENERAL

SandRidge Energy, Inc. is an independent oil and natural gas company headquartered in Oklahoma City, Oklahoma, concentrating on development and production activities in the Mid-Continent, Gulf of Mexico and Permian Basin in west Texas. The Company's primary area of focus is the Mississippian formation, a shallow hydrocarbon system in the Mid-Continent area of northern Oklahoma and Kansas, where it had approximately 1,886,000 net acres under lease at December 31, 2012. The Company also had approximately 457,000 and 232,000 net acres in the Gulf of Mexico and the Permian Basin, respectively, under lease at December 31, 2012 and owns and operates other interests in the Mid-Continent, west Texas and Gulf Coast. As described below, the Company entered into an agreement during December 2012 to sell a significant portion of its oil and natural gas properties in the Permian Basin. For more information, see "—2012 Developments—Sale of Permian Properties."

As of December 31, 2012, the Company had 6,082 gross (5,066.1 net) producing wells, a substantial portion of which it operates, and approximately 4,274,000 gross (2,941,000 net) total acres under lease. As of December 31, 2012, the Company had 33 rigs drilling in the Mid-Continent, two rigs drilling in the Gulf of Mexico, and four rigs drilling in the Permian Basin. Total estimated proved reserves as of December 31, 2012 were 565.9 MMBoe, of which approximately 58% were oil, including NGLs, and approximately 57% were proved developed.

The Company also operates businesses that are complementary to its primary development and production activities, including gas gathering and processing facilities, an oil and natural gas marketing business and an oil field services business, including its wholly owned drilling rig business, Lariat Services, Inc. ("Lariat"). As of December 31, 2012, the Company's drilling rig fleet consisted of 30 operational rigs. These complementary businesses provide the Company with operational flexibility and an advantageous cost structure by reducing the Company's dependence on third parties for these services. The Company also transports carbon dioxide ("CO_2") to the Permian Basin for use in tertiary recovery projects. "SandRidge CO_2" refers to the Company's wholly owned subsidiary SandRidge CO_2, LLC.

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 http://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 http://www.sec.gov.

BUSINESS STRATEGY

The Company's primary objectives are to achieve long-term growth and maximize stockholder value over multiple business cycles by pursuing the following strategies:

- Concentrate in Core Operating Areas. The Company's primary areas of operation are (1) the Mid-Continent area of Oklahoma and Kansas and (2) the shallow water Gulf of Mexico. By concentrating in these core areas, the Company is able to (i) further build and utilize its technical expertise in order to interpret specific geological and operational trends, (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 and produced water disposal systems and (iv) opportunistically grow its holdings and operations in these areas to achieve production and reserve growth.

- Focus on Conventional and Proven Reservoirs. The Company focuses its on-shore 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.

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The Company's offshore assets are primarily in the shallow waters of the Gulf of Mexico, which is a mature area that has been heavily explored and developed. The Company believes that there is still an abundance of low risk projects on the Gulf of Mexico shelf that offer attractive returns. These properties are being extensively reviewed for additional drilling and recompletion opportunities to fully exploit the remaining potential.

- Invest in Infrastructure to Support Growth in Core Area. By constructing a saltwater disposal system and electrical infrastructure to service the Mississippian formation, 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.
- 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.
- Maintain Flexibility. The Company has multi-year inventories of both oil and natural gas drilling locations within its core operating areas. Additionally, the Company maintains its own fleet of drilling rigs through Lariat. 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.
- Asset Monetization. The Company periodically evaluates its properties to identify opportunities to monetize assets to fund or accelerate development within its areas of focus, and may use proceeds realized from such transactions to fund the drilling and development of its core areas, for general corporate purposes or to retire corporate debt.

2012 DEVELOPMENTS

Acquisitions

Dynamic Acquisition. In April 2012, the Company acquired 100% of the equity interests of Dynamic Offshore Resources, LLC ("Dynamic") for approximately $1.2 billion, comprised of approximately $680.0 million in cash and approximately 74 million shares of the Company's common stock (the "Dynamic Acquisition"). Dynamic is an oil and natural gas exploration, development and production company with operations in the Gulf of Mexico. The Dynamic Acquisition expanded the Company's presence in the Gulf of Mexico, adding oil and natural gas reserves and production to its existing asset base in this area.

Acquisition of Gulf of Mexico Properties. In June 2012, the Company acquired additional oil and natural gas properties in the Gulf of Mexico located on approximately 184,000 gross (103,000 net) acres for approximately $38.5 million, net of purchase price adjustments and subject to post-closing adjustments.

Divestitures

Sale of Working Interest in Mississippian Properties. In January 2012, the Company sold (i) non-operated working interests, equal to approximately 250,000 net acres, in the Mississippian formation in western Kansas and (ii) non-operated working interests, equal to approximately 114,000 net acres, and a proportionate share of existing salt water disposal facilities in the Mississippian formation in northern Oklahoma and southern Kansas to Repsol E&P USA Inc. ("Repsol") for approximately $250.0 million. In addition, Repsol agreed to pay the development costs related to its working interest, as well as a portion of the Company's development costs equal to 200% of Repsol's working interest for wells within an area of mutual interest up to $750.0 million. The Company expects Repsol's funding of the Company's development cost for wells within the area of mutual interest to occur over a three-year period.

Sale of Tertiary Recovery Properties. In June 2012, the Company sold its tertiary recovery properties located in the Permian Basin area of west Texas for $130.8 million, net of post-closing adjustments. Approximately 0.4% and 1.3%

of the Company's combined production volumes for the years ended December 31, 2012 and 2011, respectively, were produced from the tertiary properties.

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Sale of Permian Properties. In December 2012, the Company entered into an agreement to sell all of its oil and natural gas properties in the Permian Basin in west Texas, excluding the assets attributable to the SandRidge Permian Trust area of mutual interest (the "Permian Properties"), for $2.6 billion, subject to post-closing adjustments. At December 31, 2012, the Permian Properties had associated proved reserves of 198.9 MMBoe with a PV-10 value of $3.2 billion. PV-10 generally differs from the Standardized Measure of Discounted Net Cash Flows ("Standardized Measure") because it does not include the effects of income taxes on future net revenues. For a reconciliation of PV-10 to Standardized Measure, see "Management's Discussion and Analysis—Overview" in Item 7 of this report. The estimated Standardized Measure attributable to the Permian Properties was approximately $2.5 billion at December 31, 2012. For the year ended December 31, 2012, production, revenues and direct operating expenses for the Permian Properties were 8.7 MMBoe, $566.1 million, and $130.3 million, respectively. The transaction closed on February 26, 2013.

Royalty Trust Offering

In April 2012, SandRidge Mississippian Trust II (the "Mississippian Trust II") completed its initial public offering of 29,900,000 common units representing approximately 60.1% of the beneficial interests in the Mississippian Trust II. Concurrent with the closing of the offering, the Company conveyed certain royalty interests to the Mississippian Trust II in exchange for the net proceeds of the offering and 19,825,000 units, representing approximately 39.9% of the beneficial interest, in the Mississippian Trust II. Net proceeds to the Company, after underwriting discounts and commissions, were approximately $587.1 million.

The Company and one of its wholly owned subsidiaries entered into a development agreement with the Mississippian Trust II that obligates the Company to drill, or cause to be drilled, a specified number of wells, which are also subject to a royalty interest, by December 31, 2016. One of the Company's wholly owned subsidiaries also granted to the Mississippian Trust II a lien on the Company's interests in the properties where the development wells are to be drilled, in order to secure the estimated amount of the drilling costs for the wells.

The Company has determined that the Mississippian Trust II is a variable interest entity ("VIE") and that the Company is the primary beneficiary. As a result, the Company began consolidating the activities of the Mississippian Trust II into its results of operations in April 2012. See "Note 4—Variable Interest Entities" to the Company's consolidated financial statements included in Item 8 of this report for further discussion of the Mississippian Trust II.

Debt Transactions

Issuance of 8.125% Senior Notes due 2022. In April 2012, concurrent with the closing of the Dynamic Acquisition, the Company issued $750.0 million of unsecured 8.125% Senior Notes due 2022 pursuant to Rule 144A and Regulation S under the Securities Act. Net proceeds from the offering were approximately $730.1 million after deducting offering expenses, and were used to finance the cash portion of the Dynamic Acquisition purchase price and to pay related fees and expenses, with any remaining amount used for general corporate purposes.

Issuance of 7.5% Senior Notes due 2021 and 2023. In August 2012, the Company issued $825.0 million of unsecured 7.5% Senior Notes due 2023 and $275.0 million of additional unsecured 7.5% Senior Notes due 2021. Net proceeds from this offering were approximately $1.1 billion, after deducting offering expenses and excluding accrued interest funded through the offering, and were used to fund the Company's tender offer for, and subsequent redemption of, its Senior Floating Rate Notes due 2014 ("Senior Floating Rate Notes"), as described below, to fund the Company's capital expenditures and for general corporate purposes. As a result of these issuances, the Company's borrowing base under its senior secured revolving credit facility (the "senior credit facility") was reduced to $775.0 million from $1.0 billion.

Tender Offer and Redemption of Senior Floating Rate Notes. In August 2012, the Company purchased $329.9 million of the aggregate principal amount of its Senior Floating Rate Notes pursuant to a tender offer. In September 2012, the Company redeemed the remaining outstanding $20.1 million aggregate principal amount of its Senior Floating Rate Notes at par value, plus accrued interest.

Senior Notes Exchange Offers. In November 2012, the Company completed exchange offers to replace its 8.125% Senior Notes due 2022 that were issued in April 2012 and its 7.5% Senior Notes due 2023 and additional 7.5% Senior Notes due 2021 that were issued in August 2012 with equivalent notes that were registered under the Securities Act. The exchange offers did not result in the incurrence of any additional indebtedness.

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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 23—Business Segment Information” 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 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 reserves, 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 the Gulf of Mexico, Permian Basin, West Texas Overthrust (“WTO”) and Gulf Coast.

The following table presents information concerning the Company’s exploration and production activities by area of operation as of December 31, 2012, unless otherwise noted.

	Estimated Net Proved Reserves (MMBoe)	PV-10 (in millions)(1)	Daily Production (MBoe/d)(2)	Reserves/ Production (Years)(3)	Gross Acreage	Net Acreage
Area						
Mid-Continent	235.8	$ 2,317.6	40.3	16.0	2,729,487	1,938,948
Gulf of Mexico	54.3	1,339.5	29.8	5.0	761,047	456,819
Permian Basin	235.6	3,980.8	27.7	23.3	322,159	231,586
Other(4)	40.2	(149.5)	10.4	10.6	461,720	313,328
Total	565.9	$ 7,488.4	108.2	14.3	4,274,413	2,940,681

(1) PV-10 generally differs from the Standardized Measure because it does not include the effects of income taxes on future net revenues. For a reconciliation of PV-10 to Standardized Measure, see “—Proved Reserves.” The Company’s total Standardized Measure was $5.8 billion at December 31, 2012.

(2) Average daily net production for the month of December 2012.

(3) Estimated net proved reserves as of December 31, 2012 divided by production for the month of December 31, 2012 annualized.

(4) PV-10 includes costs associated with a 30-year CO_2 treating agreement. Associated reserves are economically producible exclusive of these post-production costs. For further discussion of this treating agreement, see “Properties—Other” below.

Properties

Mid-Continent

The Company held interests in approximately 2,729,000 gross (1,939,000 net) leasehold acres in Oklahoma and Kansas at December 31, 2012. Associated proved reserves at December 31, 2012 totaled 235.8 MMBoe, 48% of which were proved developed reserves, based on estimates prepared by Netherland, Sewell & Associates, Inc. (“Netherland Sewell”) and the Company’s internal engineers. The Company’s interests in the Mid-Continent as of December 31, 2012 included 1,270 gross (677.3 net) producing wells with an average working interest of 53.3%. Average daily net production from the Mid-Continent area was approximately 40.3 MBoe for the month of December

2012. The Company had 33 rigs operating in the Mid-Continent as of December 31, 2012, of which one was drilling a saltwater disposal well and 32 were drilling horizontal wells in the Mississippian formation.

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Mississippian Formation. The Company's primary focus 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. The formation's geology is well understood as a result of the thousands of vertical wells drilled and produced there since the 1940s and the more than 1,365 horizontal wells drilled there since the beginning of 2007. At December 31, 2012, the Company had approximately 2,632,000 gross (1,886,000 net) acres under lease, of which approximately 115,800 gross (94,100 net) acres were included in the Mississippian Trust I and the Mississippian Trust II's areas of mutual interest.

In 2007, the application of horizontal cased-hole drilling and multi-stage hydraulic fracturing treatments demonstrated the potential for extracting significant additional quantities of oil and natural gas from the Mississippian formation. Since the beginning of 2007, there have been over 1,365 horizontal wells drilled in the formation, including approximately 600 drilled by the Company as of December 31, 2012. From December 31, 2011 to December 31, 2012, the number of the Company's producing horizontal wells in the Mississippian formation increased from 174 to 649. The Company drilled a total of 396 horizontal wells in the Mississippian formation during 2012, including 142 wells 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 from the Mississippian formation. The saltwater disposal system, which included 113 active wells and approximately 600 miles of gathering lines at December 31, 2012, reduces the overall cost of water disposal, which directly reduces production costs. The Company's electrical infrastructure, which consisted of approximately 500 miles of power lines at December 31, 2012, distributes electricity to the Company's Mississippian formation 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 of Mexico

The Company's Gulf of Mexico operations, a substantial portion of which were acquired during the second quarter of 2012 with the Dynamic Acquisition and additional Gulf of Mexico properties, primarily extend from the coast to more than 100 miles offshore and occur in 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.

As of December 31, 2012, the Company owned oil and natural gas properties in the federal and state waters in the Gulf of Mexico consisting of approximately 761,000 gross (457,000 net) leasehold acres, 339 gross (202.0 net) productive wells and 350 miles of pipeline gathering systems. Associated proved reserves at December 31, 2012 were approximately 54.3 MMBoe, of which 58% was oil, including NGLs, and 70% was proved developed. The Company operates approximately 94% of these assets, based on PV-10 values as of December 31, 2012. Average daily net production from the Gulf of Mexico was approximately 29.8 MBoe for the month of December 2012. The Company had two rigs operating in the Gulf of Mexico as of December 31, 2012.

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.

Permian Basin

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 Company significantly expanded its holdings in the Permian Basin, specifically in the Central Basin Platform (“CBP”), through the acquisition of Arena Resources, Inc. (“Arena”) in July 2010 (the “Arena Acquisition”). Reserves and associated production in this area are predominantly oil.

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The Company held interests in approximately 322,000 gross (232,000 net) leasehold acres in the Permian Basin at December 31, 2012, of which approximately 16,600 gross (15,300 net) acres were included in the Permian Trust's area of mutual interest. Associated proved reserves at December 31, 2012 were 235.6 MMBoe, 55% of which were proved developed reserves, based on estimates provided by Netherland Sewell and Lee Keeling and Associates, Inc. ("Lee Keeling"). The Company's interests in the Permian Basin as of December 31, 2012 included 3,458 gross (3,298.2 net) producing wells with an average working interest of 95.4%. Average daily net production from the Company's Permian Basin properties was approximately 27.7 MBoe for the month of December 2012. The Company had four rigs operating in the Permian Basin as of December 31, 2012 and drilled 717 wells in this area during 2012, of which 269 were subject to the Permian Trust's royalty interest.

As discussed in "2012 Developments" above, the Company completed the sale of all of its oil and natural gas properties in the Permian Basin, excluding assets attributable to the Permian Trust's area of mutual interest, in February 2013.

Other

West Texas Overthrust. 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. Low natural gas prices continue to limit development activity in this area. The Company held interests in approximately 257,000 gross (215,000 net) leasehold acres in the WTO at December 31, 2012. The Company's average daily net production in this area was approximately 7.9 MBoe for the month of December 2012.

Pursuant to a 30-year treating agreement the Company entered into with Occidental Petroleum Corporation ("Occidental"), the Company will deliver natural gas to Occidental's CO_2 treatment plant in Pecos County, Texas (the "Century Plant"), and Occidental will remove CO_2 from the Company's delivered natural gas production volumes. The Company will retain all methane gas after treatment. Under this agreement, the Company is required to deliver certain minimum CO_2 volumes annually, and is required to compensate Occidental to the extent such requirements are not met. The Company accrued $8.5 million at December 31, 2012 for the Company's shortfall in meeting its 2012 delivery obligation. Based upon projected natural gas production levels, the Company expects to accrue between approximately $29.5 million and $36.0 million during the year ending December 31, 2013 for amounts related to the Company's anticipated shortfall in meeting its 2013 annual delivery obligation. Due to the sensitivity of natural gas production to prevailing market prices, the Company is unable to estimate additional amounts it may be required to pay under this agreement in subsequent periods.

Gulf Coast. As of December 31, 2012, the Company owned oil and natural gas interests in approximately 173,000 gross (75,000 net) acres in the Gulf Coast area, which encompasses the coastal plain from the southernmost tip of Texas through the southern portion of Louisiana. The Company's average daily net production in this area was approximately 2.5 MBoe for the month of December 2012.

Proved Reserves

Preparation of Reserve Estimates

The estimates of oil and natural gas 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.

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SandRidge's Executive Vice President—Corporate Reserves and Acquisitions and Divestitures is the technical person primarily responsible for overseeing the preparation of the Company's reserves estimates. He has a Bachelor of Science degree in Mechanical Engineering with over 30 years of practical industry experience, including over 25 years of estimating and evaluating reserve information. In addition, SandRidge's Executive Vice President—Corporate Reserves and Acquisitions and Divestitures has been a certified professional engineer in the state of Oklahoma since 1988 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 department currently has a total of 23 full-time employees, comprised of seven degreed engineers, one degreed geologist and 15 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 President, independently from all of the Company's operating divisions.
- 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 Executive Vice President—Corporate Reserves and Acquisitions and Divestitures 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 Executive Vice President—Corporate Reserves and Acquisitions and Divestitures 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, Treasurer 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 third-party engineer at Netherland Sewell who is primarily responsible for the reserve report. The Audit Committee also periodically meets with the other independent petroleum consultants that prepare estimates of proved reserves.

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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 and natural gas for the years shown.

	December 31,					
	2012		2011		2010	
Netherland, Sewell & Associates, Inc.	72.7	%	80.5	%	71.9	%
Lee Keeling and Associates, Inc.	24.9	%	15.6	%	20.3	%
DeGolyer and MacNaughton	—	%	—	%	4.3	%
Total	97.6	%	96.1	%	96.5	%

The remaining 2.4%, 3.9% and 3.5% of the Company's estimated proved reserves as of December 31, 2012, 2011 and 2010, 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, NGL and natural gas reserves for substantially all geographic locations as of December 31, 2012 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, 2012 is presented below.

	Geographic Locations—by Area by State
Netherland, Sewell & Associates, Inc.	Mid-Continent—KS, OK Permian Basin—TX Gulf of Mexico WTO—TX Gulf Coast—LA, TX
Lee Keeling and Associates, Inc.	Permian Basin—NM, 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.

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 and Master of Science Degree in Geology.

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.

DeGolyer and MacNaughton

- 35 years of experience in oil and gas reservoir studies and reserve evaluations at the time of its most recent report;
- a registered professional engineer in the state of Texas; and
- a Bachelor of Science Degree in Petroleum Engineering.

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Technologies

Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible, 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 and/or natural gas 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 or natural 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 (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.

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Reserve Quantities, PV-10 and Standardized Measure

The following estimates of proved oil and natural gas reserves are based on reserve reports as of December 31, 2012, 2011 and 2010, substantially all of which were prepared by independent petroleum engineers. The following estimates of proved NGL reserves are based on reserve reports as of December 31, 2012, 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 oil and natural gas 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 period ended December 31, 2012, 2011 and 2010, using first-day-of-the-month prices for each month. The Company estimates that approximately 80% of its current proved undeveloped reserves will be developed by the end of 2014 and all of its current proved undeveloped reserves will be developed by the end of 2016. See "Critical Accounting Policies and Estimates" in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates.

	December 31,		
	2012	2011	2010
Estimated Proved Reserves(1)			
Developed			
Oil (MMBbls)	136.6	118.7	92.0
NGL (MMBbls)(2)	33.8	—	—
Natural gas (Bcf)(3)	896.7	670.4	784.3
Total proved developed (MMBoe)	319.9	230.4	222.7
Undeveloped			
Oil (MMBbls)	125.4	126.1	160.1
NGL (MMBbls)(2)	34.2	—	—
Natural gas (Bcf)(3)	518.3	684.7	978.4
Total proved undeveloped (MMBoe)	246.0	240.2	323.2
Total Proved			
Oil (MMBbls)	262.0	244.8	252.1
NGL (MMBbls)(2)	68.0	—	—
Natural gas (Bcf)(3)	1,415.0	1,355.1	1,762.7
Total proved (MMBoe)(4)	565.9	470.6	545.9
PV-10 (in millions)(5)	$7,488.4	$6,875.9	$4,509.2
Standardized Measure of Discounted Net Cash Flows (in millions)(4)(6)	$5,840.4	$5,216.3	$3,683.5

(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)	Natural gas (per Mcf)
December 31, 2012	$91.21	$2.76	$91.65	$2.29
December 31, 2011	$92.71	$4.12	$85.77	$4.06
December 31, 2010	$75.96	$4.38	$66.93	$3.80

(a) At December 31, 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. At December 31, 2011 and 2010, weighted

average wellhead prices for oil included NGLs.

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(2) Prior to 2012, NGLs did not comprise a significant portion of total proved reserves and were included with oil reserves, which affects the comparability of estimated reserves in 2012 to 2011 and 2010.

(3) The Company's production from the WTO contains natural gas that is high in CO_2 content. These amounts are net of CO_2 volumes that exceed pipeline quality specifications.

(4) At December 31, 2012 and 2011, estimated total proved reserves attributable to noncontrolling interests were approximately 38.2 and 26.4 MMBoe, respectively, and Standardized Measure attributable to noncontrolling interests were approximately $952.7 million and $932.8 million, respectively. There were no proved reserves or Standardized Measure attributable to noncontrolling interests at December 31, 2010. See "Note 25—Supplemental Information on Oil and Natural Gas Producing Activities" in Item 8 of this report for additional information regarding reserve and Standardized Measure amounts attributable to noncontrolling interests.

(5) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using 12-month average prices for the years ended December 31, 2012, 2011 and 2010. 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, 2012	2011	2010
	(In millions)		
Standardized Measure of Discounted Net Cash Flows	$5,840.4	$5,216.3	$3,683.5
Present value of future income tax discounted at 10%	1,648.0	1,659.6	825.7
PV-10	$7,488.4	$6,875.9	$4,509.2

(6) Standardized Measure represents the present value of estimated future cash inflows from proved oil and natural gas 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 in the Mid-Continent, primarily the Mississippian formation, increased from 63.0 MMBoe at December 31, 2010 to 145.5 MMBoe at December 31, 2011 and to 235.8 MMBoe at December 31, 2012, which comprise a significant portion of the additions to the Company's proved reserves in both years. For the Company's Mississippian formation development, continuity of the formation across the development area was established by reviewing electric well logs, geologically mapping the analogous reservoir and reviewing extensive production data from more than 1,400 vertical wells and a growing population of horizontal wells. The reserves attributable to producing wells and the continuity of the formation over the development area further supports proved undeveloped classification within close proximity to the producing wells. Data from both the Company and offset operators 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.

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 CBP, 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.

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

	Year Ended December 31,		
	2012	2011	2010
Reserves converted from proved undeveloped to proved developed (MMBoe)	42.6	50.3	37.4
Drilling capital expended to convert proved undeveloped reserves to proved developed reserves (in millions)	$718.2	$817.0	$480.7

The Company recognized a net addition to oil and natural gas 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 and Permian Basin areas, are a result of successful drilling. These additions were partially offset by downward revisions of reserve quantities primarily from the Piñon Field 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 and natural gas 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 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.

In 2010, the Company recognized additional oil and natural gas reserves attributable to extensions and discoveries as a result of successful drilling in the Permian Basin and Mid-Continent areas. The 12-month average natural gas index price of $4.38 per Mcf used in the estimation of natural gas reserves as of December 31, 2010, compared to the 12-month average natural gas index price of $3.87 per Mcf for 2009, resulted in upward revisions of quantities associated with the Company's proved undeveloped properties. There were no downward revisions as a result of the 12-month average oil index price used in the estimation of reserves as of December 31, 2010.

For additional information regarding changes in the Company's proved reserves during the three years ended December 31, 2012, 2011 and 2010 see "Note 25—Supplemental Information on Oil and Natural Gas Producing Activities" to the Company's consolidated financial statements in Item 8 of this report.

Significant Fields

The Mississippi Lime Horizontal, Fuhrman-Mascho and Piñon fields each contained more than 15% of the Company's total proved reserves at December 31, 2012, 2011 or 2010. These fields are described further below.

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 had estimated proved oil and natural gas reserves in the Mississippi Lime Horizontal Field of 226.6 MMBoe as of December 31, 2012. The Company's interests in the Mississippi Lime Horizontal Field as of December 31, 2012 included 649 gross (423.9 net) producing wells and a 65.3% average working interest in the producing area.

Fuhrman-Mascho Field. The Fuhrman-Mascho Field is located near the center of the CBP in the Permian Basin and produces from the Grayburg-San Andres formation from average depths of approximately 4,000 to 5,000 feet. The Company had estimated proved oil and natural gas reserves in the Fuhrman-Mascho Field of 85.7 MMBoe as of December 31, 2012. The Company's interests in the Fuhrman-Mascho Field as of December 31, 2012 included 2,095

gross (2031.2 net) producing wells and a 97% average working interest in the producing area. The Company sold properties located in the Fuhrman-Mascho field and elsewhere in the Permian Basin in February 2013 as discussed in "2012 Developments."

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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 5,000 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. As of December 31, 2012, the Company's estimated proved oil and natural gas reserves in the Piñon Field were 29.8 MMBoe.

The following table presents oil and natural gas production for the years presented, for fields containing more than 15% of the Company's total proved reserves in that year.

	Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Year Ended December 31, 2012			
Mississippi Lime Horizontal	4,636	33,034	10,142
Fuhrman-Mascho	4,665	1,768	4,960
Year Ended December 31, 2011			
Mississippi Lime Horizontal	1,210	8,332	2,598
Fuhrman-Mascho	3,769	1,633	4,041
Piñon	41	28,246	4,749
Year Ended December 31, 2010			
Fuhrman-Mascho(1)	1,468	714	1,587
Piñon	61	40,315	6,780

(1) Production is from the date property was acquired, or July 16, 2010, through December 31, 2010.

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Production and Price History

The following tables set forth information regarding the Company's net oil and natural gas production and certain price and cost information for each of the periods indicated. Because of the relatively high volumes of CO_2 produced with natural gas in certain areas of the WTO, the Company's reported sales and reserves volumes and the related unit prices received for natural gas in these areas are reported net of CO_2 volumes removed at the gas treating plants. The gas treating plant fees for removing CO_2 from the Company's natural gas that has high CO_2 content are included in the Company's lease operating expenses as processing, treating and gathering fees. All natural gas delivered to sales points with CO_2 levels within pipeline specifications is included in sales and reserves volumes.

	Year Ended December 31,		
	2012	2011	2010
Production Data			
Oil (MBbls)(1)	17,962	11,830	7,386
Natural gas (MMcf)	93,549	69,306	76,226
Total volumes (MBoe)	33,553	23,381	20,090
Average daily total volumes (MBoe/d)	91.7	64.1	55.0
Average Prices(2)			
Oil (per Bbl)(1)	$84.95	$83.21	$66.89
Natural gas (per Mcf)	$2.49	$3.50	$3.68
Total (per Boe)	$52.43	$52.47	$38.56

(1) Includes natural gas liquids.

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

	Year Ended December 31,		
	2012	2011	2010
Expenses per Boe			
Lease operating expenses			
Transportation	$0.89	$0.71	$0.60
Processing, treating and gathering(1)	1.18	1.59	1.92
Other lease operating expenses(2)	11.56	10.73	8.54
Total lease operating expenses	$13.63	$13.03	$11.06
Production taxes(3)	$1.41	$1.97	$1.45
Ad valorem taxes	$0.59	$0.78	$0.78

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

(2) For the year ended December 31, 2012, includes $8.5 million for amounts related to the Company's shortfall in meeting its 2012 CO_2 delivery obligations under a CO_2 treating agreement as described under "—Properties—Other" above.

(3) Net of severance tax refunds.

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Productive Wells

The following table sets forth the number of productive wells in which the Company owned a working interest at December 31, 2012. 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	742	461.5	528	215.8	1,270	677.3
Gulf of Mexico	253	156.4	86	45.6	339	202.0
Permian Basin	3,356	3,225.4	102	72.8	3,458	3,298.2
Other	46	25.6	969	863.0	1,015	888.6
Total	4,397	3,868.9	1,685	1,197.2	6,082	5,066.1

Developed and Undeveloped Acreage

The following table sets forth information regarding the Company's developed and undeveloped acreage at December 31, 2012:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Area				
Mid-Continent	363,520	237,491	2,365,967	1,701,457
Gulf of Mexico	695,404	401,492	65,643	55,327
Permian Basin	127,345	105,004	194,814	126,582
Other	201,824	107,252	259,896	206,076
Total	1,388,093	851,239	2,886,320	2,089,442

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, 2012 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, 2013	765,666	546,973
December 31, 2014	1,134,765	809,999
December 31, 2015	299,081	231,168
December 31, 2016 and later	560,074	412,584
Other(1)	126,734	88,718
Total	2,886,320	2,089,442

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

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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, 2012, the Company had 142 gross (111.1 net) operated wells drilling, completing or awaiting completion.

	2012				2011				2010			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Completed Wells												
Development												
Productive	1,054	99.8 %	930.9	99.8 %	895	99.7 %	850.0	99.7 %	579	95.7 %	538.8	95.7 %
Dry	2	0.2 %	1.7	0.2 %	3	0.3 %	2.9	0.3 %	26	4.3 %	24.3	4.3 %
Total	1,056	100.0 %	932.6	100.0 %	898	100.0 %	852.9	100.0 %	605	100.0 %	563.1	100.0 %
Exploratory												
Productive	32	97.0 %	24.3	96.0 %	38	100.0 %	33.7	100.0 %	15	83.3 %	14.9	83.2 %
Dry	1	3.0 %	1.0	4.0 %	—	— %	—	— %	3	16.7 %	3.0	16.8 %
Total	33	100.0 %	25.3	100.0 %	38	100.0 %	33.7	100.0 %	18	100.0 %	17.9	100.0 %
Total												
Productive	1,086	99.7 %	955.2	99.7 %	933	99.7 %	883.7	99.7 %	594	95.3 %	553.7	95.3 %
Dry	3	0.3 %	2.7	0.3 %	3	0.3 %	2.9	0.3 %	29	4.7 %	27.3	4.7 %
Total	1,089	100.0 %	957.9	100.0 %	936	100.0 %	886.6	100.0 %	623	100.0 %	581.0	100.0 %

Drilling Rigs

The following table sets forth information with respect to the rigs operating on the Company's acreage by area as of December 31, 2012.

	Owned	Third-Party	Total
Mid-Continent	11	22	33
Gulf of Mexico	—	2	2
Permian Basin	3	1	4
Total	14	25	39

Marketing and Customers

The Company sells oil, natural gas and natural gas liquids 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 2012. See "Note 23—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 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.

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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.

Capital Expenditures

The Company's capital expenditures for 2012 related to its exploration and production segment were $2.0 billion, including amounts spent to develop wells in the Royalty Trust areas of mutual interest. The Company has budgeted approximately $1.55 billion in capital expenditures, excluding acquisitions, in 2013 for its exploration and production segment.

Drilling and Oil Field Services

The drilling and related oil field services that the Company provides 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, Lariat. In addition, the Company also 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, 2012, the Company's drilling rig fleet consisted of 30 operational rigs with 14 of these rigs working on Company-owned properties in the Mid-Continent and Permian Basin.

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 2012, the Company performed approximately 69% of its drilling and oil field services in support of its exploration and production business. For the years ended December 31, 2012, 2011 and 2010, the Company generated revenues of $116.6 million, $103.3 million and $28.6 million, respectively, for drilling and oil field services performed for third parties.

Capital Expenditures

The Company’s capital expenditures for 2012 related to its drilling and oil field services were $27.5 million. The Company has budgeted approximately $30.0 million in capital expenditures in 2013 for its drilling and oil field services segment.

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Midstream Services

The Company's midstream services segment primarily provides gathering, compression and treating services of natural gas in west Texas. 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.

West Texas

The Company owns the Pike's Peak gas treating plant in Pecos County, Texas, and the Grey Ranch gas treating plant located in Pecos County and has a 50% interest in the partnership that leases the Grey Ranch plant from the Company under a lease expiring in 2020. As a result of depressed natural gas prices and the treating capabilities of the recently completed Century Plant, these gas treating plants were used in a limited capacity during 2012.

The Century Plant, which was substantially completed in the fourth quarter of 2012, provides 675 MMcf per day in available treating capacity in the west Texas area. Upon substantial completion of Phase I and Phase II during the third and fourth quarters of 2012, respectively, Occidental took ownership of and began operating the plant for the purpose of separating and removing CO_2 from the delivered natural gas stream. The Company diverted a majority of its high CO_2 natural gas production from its legacy gas treating plants to the Century Plant beginning in 2011 and throughout 2012. In 2011, the Company evaluated its gas treating plants and CO_2 compression facilities for impairment in connection with the operational assessment of Phase I of the Century Plant and concluded no impairment was necessary. The Company continued to monitor the status of the Century Plant, the related impact on its gas treating plants and CO_2 compression facilities and natural gas prices during 2012. In the fourth quarter of 2012, the Company evaluated its gas treating plants and CO_2 compression facilities for impairment in connection with the substantial completion of Phase II of the Century Plant. Due to prevailing low natural gas prices, the Company's natural gas production is not projected to reach the available treating capacity at the Century Plant. As such, the Company anticipates the use of its gas treating plants and CO_2 compression facilities in west Texas will be very limited, and accordingly, recorded a $79.3 million impairment on its gas treating plants and CO_2 compression facilities.

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 16—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.

Mid-Continent

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

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 "back-to-back" 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 periodically buys and sells third-party natural gas. 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 and 50,000 MMBtu per day on Mid-Continent Express Pipeline through March 2019. See “Note 16—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.

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Customers

During 2012, the Company performed approximately 67% of its midstream services in support of its exploration and production business. For the years ended December 31, 2012, 2011 and 2010, the Company generated revenues of $38.8 million, $65.2 million and $98.5 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 development operations. Historically, pipeline and facility expansions are made when warranted by the increase in production or the development of additional acreage. During 2012, the Company spent $195.0 million in capital expenditures to install electrical and compression infrastructure and for other general corporate purposes. The Company has budgeted approximately $170.0 million in 2013 capital expenditures for its midstream services segment and for other general corporate purposes.

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 and natural gas. 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 and natural gas 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 and natural gas 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 and natural gas 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 and natural gas 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 and natural gas.

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.

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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. For example, tropical storms and hurricanes typically occur in the Gulf of Mexico during the summer and fall, which may require the Company to evacuate personnel and shut in production until the storms subside. 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.

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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, on January 16, 2013, the EPA made an unopposed motion in federal court to seek an abeyance of legal challenges to the regulations while it reconsiders and potentially revises portions of the new rules. 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.

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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, U.S. 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.

The Clean Water Act also requires owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. The Clean Water Act currently requires a minimum financial responsibility demonstration of $35 million for companies operating on the Outer Continental Shelf, although the Secretary of Interior may increase this amount up to $150 million in certain situations. As a result of the Deepwater Horizon incident, legislation was introduced, but not adopted, to increase the minimum level of financial responsibility to $300 million or more. Whether similar legislation will be introduced and adopted in the future is unknown. If such legislation were to be adopted, this requirement could have a material adverse effect on the Company's operations.

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 onshore and offshore 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.

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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. 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.

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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 proposal is expected to be published in the first quarter of 2013.

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 final report expected to be issued 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.

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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 and natural gas are not currently regulated and are made at market prices. Although oil and natural gas 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 and natural gas 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.

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Effective October 1, 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE," formerly known as the Minerals Management Service), the agency within the U.S. Department of the Interior responsible for regulation of offshore energy production, was divided into two agencies, the Bureau of Safety and Environmental Enforcement ("BSEE") and the Bureau of Ocean Energy Management ("BOEM"). The BSEE is responsible for the safety and enforcement functions of offshore oil and natural gas operations, including development and enforcement of safety and environmental regulations, permitting, inspections, offshore regulatory programs, oil spill response and training and environmental compliance programs, while the functions of BOEM include offshore leasing, resource evaluation, National Environmental Policy Act analysis and review and administration of oil and natural gas exploration and development plans. Under some circumstances, the BOEM may require any of the Company's offshore federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect the Company's financial condition and results of operations. Additionally, for future hurricane seasons the BOEM and/or the BSEE may impose more stringent requirements than are already in place for the improvement of platform survivability in the Gulf of Mexico. New requirements, if any, could increase the Company's operating costs.

Federal, state and local regulations provide detailed requirements for the abandonment of wells, closure or decommissioning of production facilities and pipelines, and for site restoration, in areas where the Company operates. Regulations of the BSEE require that owners and operators plug and abandon wells and decommission and remove offshore facilities located in federal offshore lease areas in a prescribed manner. BOEM requires federal leaseholders to post performance bonds or otherwise provide necessary financial assurances. 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, with additional financial security required for offshore wells. 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.

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EMPLOYEES

As of December 31, 2012, the Company had 2,510 full-time employees, including more than 450 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of the Company's 2,510 employees, 791 were located at the Company's headquarters in Oklahoma City, Oklahoma at December 31, 2012, and the remaining employees work in the Company's various field offices and drilling sites.

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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 2012 of $91.21/Bbl for oil and $2.76/Mcf for natural gas, the ratio of economic value of oil to gas was approximately 33 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 and natural gas 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.

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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.

NGLs. Natural gas liquids.

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%.

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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 and natural gas 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.

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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 and natural gas 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 and natural gas 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.

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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. 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;
- 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 and natural gas prices;
- oil and natural gas property title problems;
- unique risks associated with offshore operations, such as potential oil spills and increased regulation; and
- market limitations for oil and natural gas.

Any 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.

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Oil and natural gas prices fluctuate due to a number of factors that are beyond the Company's control, and a decline in oil and natural gas 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 and natural gas. The markets for these commodities are very volatile. Oil and natural gas 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 and natural gas, as well as perceptions of supply of, and demand for, oil and natural gas;
- 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 and natural gas, 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, 2009 through December 31, 2012, the highest monthly NYMEX settled price was $113.93 per Bbl and the lowest was $41.68 per Bbl. For natural gas, from January 1, 2009 through December 31, 2012, the highest monthly NYMEX settled price was $6.14 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 and natural gas prices may not only decrease the Company's revenues on a per share basis, but also may ultimately reduce the amount of oil and natural gas that it can produce economically and, therefore, could have a material adverse effect on its financial condition and results of operations. This also may result in the Company having to make substantial downward adjustments to its estimated proved reserves.

Future price declines may result in further 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 and natural gas 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, 2012, 2011 or 2010 and cumulative full cost ceiling limitation impairment charges of $3.5 billion at both December 31, 2012 and 2011. Future declines in oil and natural gas 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.

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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, 2012, the Company's total indebtedness was $4.3 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 development wells for the Royalty Trusts, 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 and natural gas 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 and natural gas reserves.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas 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 and natural gas prices and other factors, many of which are beyond the Company's control.

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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 and natural gas 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 also will be affected by factors such as:

- actual prices the Company receives for oil and natural gas;
- 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 and natural gas; 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 and natural gas reserves, its reserves and production will decline, which would adversely affect the Company's business, financial condition and results of operations.

The Company's future oil and natural gas 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 use of seismic data and other technologies and the study of producing fields in the same area does 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. 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. During 2012, the Company completed a total of 1,089 gross wells, of which three 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. In summary, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

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

Production of oil, natural gas and natural gas liquids 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.

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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 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, 2012, 43% 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 northwest Oklahoma, Kansas and the Gulf of Mexico, making it vulnerable to risks associated with operating in a limited number of major geographic areas.

As of December 31, 2012, excluding reserves and production related to the Permian Properties sold in February 2013, approximately 79% of the Company's proved reserves and approximately 74% of its production was located in the Mid-Continent and Gulf of Mexico. 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 and natural gas 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 and natural gas 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. The Company expects to finance its future capital expenditures with the sale of equity and debt securities, cash flow from operations, asset sales and other financing arrangements. 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 and natural gas it is able to produce from existing wells;
- the prices at which oil and natural gas 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 and natural gas 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 and natural gas 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 its 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 re-determination of the borrowing base per calendar year. Unscheduled re-determinations 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.

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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 and natural gas, 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 and natural gas 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 and natural gas production and associated activities, such as fires, leaks, explosions, mechanical problems, major equipment failures, blowouts, uncontrollable flow of oil, natural gas and natural gas liquids, 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 and natural gas 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. Historically, there have been shortages of drilling rigs and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. 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.

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Market conditions or operational impediments may hinder the Company's access to oil and natural gas markets or delay production of oil and natural gas.

Market conditions or a lack of satisfactory oil and natural gas transportation arrangements may hinder the Company's access to oil and natural gas markets or delay production of oil and natural gas. The availability of a ready market for the Company's oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas 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.

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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 an 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 2012, the Company's plant shrink has been approximately 5% in the WTO. After giving effect to plant shrink, as many as 3.3 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. A material decrease in 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. The Company is required to compensate PGC and Occidental for shortfalls in its contractual delivery obligations. The Company accrued $8.5 million at December 31, 2012 for its 2012 shortfalls under its contract with Occidental and expects to accrue between approximately $29.5 million and $36.0 million during the year ending December 31, 2013 for amounts related to the Company's anticipated shortfall in meeting its 2013 annual delivery obligations 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.

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The Company may not realize the anticipated benefits of its acquisitions of Dynamic and other properties in the Gulf of Mexico or other future acquisitions, and integration of acquisitions may disrupt the Company's business and management.

The Company acquired Dynamic and other properties in the Gulf of Mexico in the second quarter of 2012, and it may acquire other companies or large asset packages in the future as it has done in the past. The Company may not realize the anticipated benefits of these acquisitions or other future acquisitions, and each acquisition has numerous risks. These risks include:

- difficulty in assimilating the operations and personnel of the acquired company;
- difficulty in maintaining controls, procedures and policies during the transition and integration;
- disruption of the Company's ongoing business and distraction of its management and employees from other opportunities and challenges;
- difficulty integrating the acquired company's accounting, management information systems, human resources and other administrative systems;
- inability to retain key personnel of the acquired business;
- inability to achieve the financial and strategic goals for the acquired and combined businesses;
- inability to take advantage of anticipated tax benefits;
- potential failure of the due diligence processes to identify significant problems, liabilities or other shortcomings or challenges of an acquired business;
- exposure to litigation and other potential liabilities in connection with environmental laws regulating exploration and production activities related to entities that the Company acquires, or that were previously acquired by such entities;
- exposure to litigation or other claims in connection with, or inheritance of claims or litigation risk as a result of, an acquisition, including but not limited to, claims from terminated employees, customers, former stockholders or other third-parties;
- potential inability to assert that internal control over financial reporting is effective; and
- potential incompatibility of business cultures.

Offshore operations involve special risks that could adversely affect operations.

Offshore operations are subject to a variety of operating risks specific to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. Any liabilities incurred by the Company with respect to such risks could reduce or eliminate the funds available for exploration, development or leasehold acquisitions or result in loss of equipment and properties.

In addition, an oil spill on or related to offshore properties and operations could expose the Company to joint and several strict liability, without regard to fault, under applicable law 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. If an oil discharge or substantial threat of discharge were to occur, the Company may be liable for costs and damages that could be material to its business, financial condition or results of operations.

Reserves associated with properties in the Gulf of Mexico will have relatively short production periods or reserve lives.

High production rates generally result in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial few years when compared to other regions in the United States. Due to high initial production rates, production of reserves from reservoirs in the Gulf of Mexico generally decline more rapidly than from other producing reservoirs. As a result, the Company's reserve replacement needs from new prospects in the Gulf of Mexico may be greater than reserve replacement needs for other properties with longer-life reserves in other producing areas. Also, expected revenue and return on capital for Gulf of Mexico properties will depend on prices prevailing during these relatively short production periods.

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The Company may record significant estimates of future asset retirement obligations and such estimates may vary from period to period due to its operations in the Gulf of Mexico.

The Company is required to record a liability for the present value of asset retirement obligations to plug and abandon inactive, non-producing wells, to remove inactive or damaged platforms, facilities and equipment, and to restore the land or seabed at the end of oil and natural gas production operations. These costs are typically considerably more expensive for offshore operations as compared to most land-based operations, due to the logistical issues associated with working in waters of various depths and increased regulatory scrutiny. Estimating future restoration and removal costs in the Gulf of Mexico is especially difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and asset removal technologies are constantly evolving, which may result in additional or increased costs. As a result, the Company's acquisitions of offshore properties in 2012 may require the Company to make significant increases or decreases to estimated asset retirement obligations in future periods. For example, the Company's platforms, facilities and equipment in the Gulf of Mexico are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change dramatically if the host platform from which the work was anticipated to be performed is damaged or toppled, rather than structurally intact. Accordingly, the Company's increased operations in the Gulf of Mexico could cause its estimates of future asset retirement obligations to differ dramatically from what it may ultimately incur as a result of damage from a hurricane.

Insurance may not protect the Company against business and operating risks associated with its properties in the Gulf of Mexico.

The Company maintains insurance for some, but not all, of the potential risks and liabilities associated with its offshore properties. For some risks, the Company may not obtain insurance if it believes the cost of available insurance is excessive relative to the risks presented. Due to market conditions, premiums and deductibles for certain insurance policies can increase substantially and, in some instances, certain insurance policies are economically unavailable or available only for reduced amounts of coverage. Although the Company will maintain insurance at levels it believes are appropriate and consistent with industry practice, it will not be fully insured against all risks, including high-cost business interruption insurance and drilling and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on the Company's business, financial condition and results of operations. Insurance costs have generally risen in recent years due to a number of catastrophic events, including Hurricanes Ivan, Katrina, Rita, Gustav and Ike, the Deepwater Horizon incident, the September 11, 2001 terrorist attacks and the 2011 Japanese tsunami. The offshore oil and natural gas industry suffered extensive damage from the previously mentioned hurricanes and, as a result, insurance costs related to offshore oil and gas operations have increased significantly compared to the cost of insuring onshore oil and gas production. Insurers are requiring higher retention levels and limit the amount of insurance proceeds that are available after a major windstorm in the event that damages are incurred. If storm activity in the future is as severe as it was in 2005 or 2008, insurance underwriters may no longer insure Gulf of Mexico assets against weather-related damage. In addition, the Company does not have in place, and does not intend to put in place, business interruption insurance due to its high cost. If an accident or other event results in damage to offshore operations, including severe weather, terrorist acts, war, civil disturbances, pollution or environmental damage, and such damage is not fully covered by insurance or a recoverable indemnity from a vendor, it could adversely affect the Company's business, financial condition and results of operations. Moreover, the Company may not be able to maintain adequate insurance in the future at rates it considers reasonable or be able to obtain insurance against certain risks.

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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. Further, in light of the explosion and fire on the drilling rig Deepwater Horizon in the Gulf of Mexico, 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 most U.S. federal tax incentives and certain deductions available 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 in the Gulf of Mexico may face broad adverse consequences resulting from increased regulation of offshore drilling operations as a result of the Deepwater Horizon incident, some of which may be unforeseeable.

The April 2010 explosion and fire on the drilling rig Deepwater Horizon and resulting major oil spill produced significant economic, environmental and natural resource damage in the Gulf Coast region. In response to the

explosion and spill, there have been many proposals by governmental and private constituencies to address the direct impact of the disaster and to prevent similar disasters in the future. The BOEMRE (formerly known as the Minerals Management Service), the agency within the U.S. Department of Interior formerly responsible for regulation of offshore energy production, issued a series of "Notices to Lessees and Operators" ("NTLs"), which imposed a variety of new safety measures and permitting requirements, and implemented a temporary moratorium on deepwater drilling activities in the Gulf of Mexico that effectively shut down deepwater drilling activities for six months in 2010. Despite the fact that the drilling moratorium was lifted, this spill and its aftermath have led to delays in obtaining drilling permits. The Company must interact with both the BOEM and the BSEE, which assumed the responsibilities of BOEMRE on October 1, 2011, to obtain approval of exploration and development plans and issuance of drilling permits for the Company's properties in the Gulf of Mexico, which may result in added plan approval or drilling permit delays. While federal legislation previously was introduced to expedite the process for obtaining offshore permits that include limitations on the time frame for environmental and judicial review, there is no guarantee that this or similar legislation will be enacted.

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In addition to the drilling restrictions, new safety measures and permitting requirement, there have been numerous additional proposed changes in laws, regulations, guidance and policy in response to the Deepwater Horizon explosion and oil spill that could affect offshore operations and cause the Company to incur substantial losses or expenditures. Implementation of any one or more of the various proposed responses to the disaster could materially adversely affect operations in the Gulf of Mexico by raising operating costs, increasing insurance premiums, delaying drilling operations and increasing regulatory costs and, further, could lead to a wide variety of other unforeseeable consequences that could make operations in the Gulf of Mexico more difficult, time consuming and costly.

New regulatory requirements could significantly delay the Company's ability to obtain permits to drill new wells in offshore waters.

Following the Deepwater Horizon incident, the BOEMRE issued a series of NTLs and other regulatory requirements imposing new standards and permitting procedures for new wells to be drilled in federal waters of the Outer Continental Shelf. These requirements include the following:

- The Environmental NTL, which imposes new and more stringent requirements for documenting the environmental impacts potentially associated with the drilling of a new offshore well and significantly increases documentation requirements regarding the ability to respond to oil spills.
- The Statement of Compliance NTL, which imposes requirements for operators regarding well design, construction and flow intervention processes and demonstration of adequate resources to respond to and contain spills, and also requires certifications of compliance from senior corporate officers.
- The Drilling Safety Rule, which prescribes tighter cementing and casing practices, imposes standards for the use of drilling fluids to maintain wellbore integrity, and stiffens oversight requirements relating to blowout preventers and their components, including shear and pipe rams.
- The Workplace Safety Rule, which requires operators to have a comprehensive safety and environmental management system ("SEMS") in order to reduce human and organizational errors as root causes of work-related accidents and offshore spills.

In its current form, the rule requires a company's SEMS to be audited by an independent third-party auditor or internal audit team who has been pre-approved by the agency to perform the auditing task. BSEE has also drafted a statement of policy announcing its expectation that all organizations and individuals working in outer continental shelf waters should establish and maintain a positive safety culture commensurate with the significance of their activities and the nature and complexity of their organizations and functions.

As a result of the issuance of these new regulatory requirements, BSEE has been taking much longer than the Minerals Management Service and BOEMRE did in the past to review and approve permits for drilling operations. As a result, the Company may encounter increased costs associated with regulatory compliance and delays in obtaining permits for other operations such as recompletions, workovers and abandonment activities. The Company is unsure what long-term effect, if any, additional regulatory requirements and permitting procedures will have on offshore operations. The Company may become subject to a variety of unforeseen adverse consequences arising directly or indirectly from the Deepwater Horizon incident.

New regulatory requirements could have a significant impact on the Company's estimates of future asset retirement obligations from period to period.

The Company is responsible for plugging and abandoning wellbores and decommissioning associated platforms, pipelines and facilities on its acquired oil and natural gas properties. In addition to the NTLs discussed in the above risk factors, the BOEMRE issued an NTL that became effective in October 2010, which established more stringent requirements for the timely decommissioning of wells, platforms and pipelines that are no longer producing or serving exploration or support functions related to an operator's lease in the Gulf of Mexico. This NTL requires that any well that has not been used during the past five years for exploration or production or any infrastructure to support these operations on an active lease and is no longer capable of producing in paying quantities must be permanently plugged

or temporarily abandoned within three years. Plugging or abandonment of wells may be delayed by two years if all of the well's hydrocarbon and sulphur zones are appropriately isolated. Similarly, platforms or other facilities that are no longer useful for operations because they have been toppled or destroyed or have not been used in the past five years for exploration, production or for infrastructure to support such operation must be removed within five years. These regulations affecting plugging, abandonment and removal activities may increase, perhaps materially, the future plugging, abandonment and removal costs associated with the Company's offshore properties, which may translate into a need to increase the estimate of future asset retirement obligations required to meet such increased costs. Moreover, implementation of this NTL could likely result in increased demand for salvage contractors and equipment, resulting in increased estimates of plugging, abandonment and removal costs and increases in related asset retirement obligations.

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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.

Further, certain laws require owners and operators of offshore oil production facilities to establish and maintain evidence of financial responsibility to cover costs that could be incurred in responding to an oil spill. As a result of the Deepwater Horizon incident, legislation was introduced, but not adopted, to increase the minimum level of financial responsibility. Whether similar legislation will be introduced and adopted in the future is unknown. If such legislation were to be adopted, the requirement could have a material adverse effect on the Company's operations.

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.

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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 is expected to be published in the first quarter of 2013.

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 final report expected to be issued 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.

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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 onshore and offshore 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.

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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 2013, have included provisions eliminating certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. If enacted into law, these provisions would eliminate certain tax preferences 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 elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United States production activities 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. The final rules became effective on January 17, 2012 and compliance with the rules was to have become mandatory on October 12, 2012. However, on September 28, 2012 the District Court of the District of Columbia vacated the CFTC's rulemaking and remanded to the CFTC for further proceedings. On November 15, 2012, the CFTC voted to appeal the District Court's ruling. It is not clear what regulatory action, if any, the CFTC will take in response to the court's decision. However, regulations that subject the Company or its derivatives counterparties to limits on commodity positions could have an adverse effect on its ability to hedge risks associated with its business or on the cost of its hedging activity.

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Our business could be negatively affected as a result of a consent solicitation and/or proxy contest.

One of the Company's stockholders, TPG-Axon Partners, LP, and certain of its affiliates (collectively, "TPG-Axon") currently is soliciting the written consents of our stockholders to three actions being proposed by TPG-Axon. Specifically, TPG-Axon is proposing to: (1) amend the Company's bylaws to de-stagger the Board by providing that directors will be elected for one-year terms, provide that the size of the Board may be fixed by either a majority vote of the Board or vote of the stockholders, provide that vacancies on the Board may be filled by the stockholders or by a majority vote of the remaining directors of the Board, and provide that directors may be removed with or without cause; (2) remove, without cause, all seven current members of the Board; and (3) elect as directors TPG-Axon's own nominees (the "TPG-Axon Nominees"). TPG-Axon has further advocated for the removal of the Company's Chief Executive Officer and the engagement of an advisor to explore strategic alternatives, including a potential sale of the Company.

The Company's business, operating results or financial condition could be adversely affected by TPG-Axon's consent solicitation because, among other things:

- considering and responding to the consent solicitation and related actions by TPG-Axon, including, but not limited to, issues related to the qualifications of the Company's Chief Executive Officer, Board and management, has been, and may continue to be, disruptive, costly and time-consuming, and a significant distraction for the Company's management and employees;
- perceived uncertainties as to the Company's future direction, including, but not limited to, uncertainties related to the Company's Chief Executive Officer, Board and management as well as the Company's future status, may result in the loss of potential business opportunities and may make it more difficult to attract and retain qualified personnel;
- if the TPG-Axon Nominees are elected to the Company's Board of Directors and the Company's Chief Executive Officer or other senior executives are removed, it may adversely affect the Company's ability to create additional value for its stockholders by effectively implementing its business strategy;
- the removal and replacement of a majority of the Board of Directors as a result of the TPG-Axon consent solicitation could constitute a "change of control" under certain of the Company's material agreements, which could have material adverse consequences under such agreements;
- the removal and replacement of a majority of the Board as a result of TPG-Axon's consent solicitation would result in the accelerated vesting of a substantial number of shares of restricted stock held by employees and senior management, reducing the effectiveness of the restricted stock awards as tools for retaining individuals with expertise in the Company's key operating areas; and
- the actions taken by TPG-Axon have created an environment conducive to follow-on litigation, described below under Item 3, which serves as a further distraction to the Company's management and employees and requires it to incur significant costs. Costs associated with the consent solicitation, related actions, and litigation may be substantial. Further, if determined adversely, such litigation could harm the Company's business and have a material adverse effect on its results of operations.

In addition, the future trading price of the Company's common stock could be subject to wide fluctuation based on the uncertainty associated with TPG-Axon's consent solicitation.

If TPG-Axon is unsuccessful in its consent solicitation, it or other stockholders may pursue similar goals at the Company's 2013 annual meeting of stockholders, including by means of a proxy contest, which could result in the same adverse effects described above.

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Item 1B. Unresolved Staff Comments

None.

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Item 2. Properties

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

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Item 3. Legal Proceedings

On February 14, 2011, Aspen Pipeline, II, L.P. ("Aspen") filed a complaint in the District Court of Harris County, Texas, against Arena and the Company claiming damages based upon alleged representations by Arena in connection with Aspen's construction of a natural gas pipeline in west Texas. On October 14, 2011, the complaint was amended to add Odessa Fuels, LLC, Odessa Fuels Marketing, LLC and Odessa Field Services and Compression, LLC as plaintiffs. The plaintiffs' amended claims seek damages relating to the construction of the pipeline and performance under a related gas purchase agreement, which damages are alleged to approach $100.0 million. In February 2013, the parties reached an agreement to settle the lawsuit, pursuant to which the Company will pay the plaintiffs $20.0 million in cash and the lawsuit will be dismissed with prejudice, and pursuant to which the parties will further mutually release each other from all claims related to the subject matter of the lawsuit. The settlement amount was accrued as of December 31, 2012.

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 (including 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 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. It is unknown at this time whether the plaintiffs will appeal the 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 Company's 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 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 $15.0 million under the participation agreement. The plaintiffs seek compensatory and punitive damages and rescission of the participation agreement. The Company intends to defend this lawsuit vigorously and believes the plaintiffs' claims are without merit. On November 28, 2011, the defendants filed a motion to dismiss the amended complaint, which motion is still pending with the court. 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 Company's defenses are fully disclosed and analyzed. The Company has not established any reserves relating to this action.

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As disclosed under Item 1A—Risk Factors, TPG-Axon is soliciting the written consents of the Company's stockholders to three actions being proposed by TPG-Axon. Subsequent to the commencement of the consent solicitation, certain lawsuits, set forth below, were filed by Company stockholders, all of which refer to allegations made by TPG-Axon in its consent solicitation or to transactions that have been the focus of allegations by TPG-Axon:

- 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
- 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 District Court of Oklahoma County, Oklahoma

Each lawsuit identified above was filed derivatively on behalf of the Company and names as defendants the Company's current directors. The Hefner lawsuit also names as defendants certain Company senior executive officers and past directors. All five lawsuits assert substantially similar claims - generally that the defendants breached their fiduciary duties, grossly mismanaged the Company, wasted corporate assets, and engaged in, facilitated or approved self-dealing transactions. 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. Because these lawsuits have only been recently filed, an estimate of reasonably possible losses associated with them, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the Company's 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 of the Company's executive officers. 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. In each case, the plaintiffs allege that, between February 24, 2011, and November 8, 2012, the defendants made false and misleading statements, and omitted material information, concerning the Company's oil reserves and business fundamentals, and engaged in a scheme to deceive the market. The plaintiffs seek, among other relief, unspecified damages. The Company intends to defend these lawsuits vigorously. Because these lawsuits have only been recently filed, an estimate of reasonably possible losses associated with them, if any, cannot be made until the facts, circumstances and legal theories relating to the plaintiffs' claims and the Company's defenses are fully disclosed and analyzed. The Company has not established any reserves relating to these actions.

On January 7, 2013, Jerald Kallick, on behalf of himself and all other similarly situated stockholders, filed a putative class action complaint in the Court of Chancery of the State of Delaware against SandRidge Energy, Inc., and each of the Company's current directors. On January 31, 2013, the plaintiff filed an amended class action complaint. In his amended complaint, the plaintiff seeks: (i) declaratory relief that certain change-in-control provisions in the Company's indentures and credit agreement are invalid and unenforceable, (ii) declaratory relief that the directors breached their fiduciary duties by failing to approve nominees for the Board of Directors submitted by a dissident stockholder in order to avoid triggering the change-in-control provisions described above, (iii) a mandatory injunction requiring the directors to approve nominees for the Board of Directors submitted by the dissident stockholder, (iv) a

mandatory injunction prohibiting the Company from paying the Company's CEO his change-in-control benefits under his employment agreement in the event the CEO is removed as a director, but remains employed as the Company's CEO, (v) a mandatory injunction enjoining the defendants from impeding or interfering with the dissident stockholder's consent solicitation, (vi) a mandatory injunction requiring the defendants to disclose all material information related to the change-in-control provisions in the Company's indentures and credit agreement; and (vii) an order requiring the Company's current directors to account to the plaintiff and the putative class for alleged damages. The Company intends to defend this lawsuit vigorously and believes that at least part of the relief sought is now moot.

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In addition, SandRidge 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 results of operations, financial position, cash flows or liquidity.

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Item 4. Mine Safety Disclosures

Not applicable.

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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
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
2011		
Fourth Quarter	$8.57	$5.01
Third Quarter	$12.11	$5.56
Second Quarter	$12.97	$9.98
First Quarter	$12.80	$7.15

On February 22, 2013, there were 298 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 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.

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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, 2008 through December 31, 2012. 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, 2008.

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.

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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 17—Equity" to the consolidated financial statements included in Item 8 of this report for further discussion of treasury stock. During the quarter ended December 31, 2012, 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, 2012 — October 31, 2012	28,011	$7.18	N/A	N/A
November 1, 2012 — November 30, 2012	3,816	$6.27	N/A	N/A
December 1, 2012 — December 31, 2012	1,327	$5.94	N/A	N/A