SANDRIDGE ENERGY INC
Form 10-K
March 01, 2013

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

(405) 429-5500
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

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

Area	Estimated Net Proved Reserves (MMBoe)	PV-10 (in millions)(1)	Daily Production (MBoe/d)(2)	Reserves/ Production (Years)(3)	Gross Acreage	Net Acreage
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.

(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.

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.

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.

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

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Item 6. Selected Financial Data

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

	Year Ended December 31,				
	2012	2011	2010	2009	2008
	(In thousands, except per share data)				
Statement of Operations Data					
Revenues	$2,730,965	$1,415,213	$931,736	$591,044	$1,181,814
Expenses					
Production	477,154	322,877	237,863	169,880	159,545
Production taxes	47,210	46,069	29,170	4,010	30,594
Drilling and services	68,227	65,654	22,368	28,380	22,872
Midstream and marketing	39,669	66,007	90,149	80,608	189,428
Century Plant construction costs	796,323	—	—	—	—
Depreciation and depletion—oil and natural gas	568,029	317,246	265,914	168,919	285,644
Depreciation and amortization—other	60,805	53,630	50,776	50,865	70,448
Accretion of asset retirement obligations	28,996	9,368	9,421	7,108	5,273
Impairment	316,004	2,825	—	1,707,150	1,867,497
General and administrative	241,682	148,643	179,565	100,256	109,372
(Gain) loss on derivative contracts	(241,419)	(44,075)	50,872	(147,527)	(211,439)
Loss (gain) on sale of assets	3,089	(2,044)	2,424	26,419	(9,273)
Total expenses	2,405,769	986,200	938,522	2,196,068	2,519,961
Income (loss) from operations	325,196	429,013	(6,786)	(1,605,024)	(1,338,147)
Other income (expense)					
Interest expense	(303,349)	(237,332)	(247,442)	(185,316)	(143,458)
Bargain purchase gain	122,696	—	—	—	—
Loss on extinguishment of debt	(3,075)	(38,232)	—	—	—
Income from equity investments	—	—	—	1,020	1,398
Other income, net	4,741	3,122	2,558	7,272	1,454
Total other expense	(178,987)	(272,442)	(244,884)	(177,024)	(140,606)
Income (loss) before income taxes	146,209	156,571	(251,670)	(1,782,048)	(1,478,753)
Income tax benefit	(100,362)	(5,817)	(446,680)	(8,716)	(38,328)
Net income (loss)	246,571	162,388	195,010	(1,773,332)	(1,440,425)
Less: net income attributable to noncontrolling interest	105,000	54,323	4,445	2,258	855
Net income (loss) attributable to SandRidge Energy, Inc.	141,571	108,065	190,565	(1,775,590)	(1,441,280)
Preferred stock dividends and accretion	55,525	55,583	37,442	8,813	16,232
Income available (loss applicable) to SandRidge Energy, Inc. common stockholders	$86,046	$52,482	$153,123	$(1,784,403)	$(1,457,512)
Earnings (loss) per share					

Basic	$0.19	$0.13	$0.52	$(10.20)	$(9.36)
Diluted	$0.19	$0.13	$0.52	$(10.20)	$(9.36)
Weighted average number of common shares outstanding					
Basic	453,595	398,851	291,869	175,005	155,619
Diluted	456,015	406,645	315,349	175,005	155,619

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	As of December 31,				
	2012	2011	2010	2009	2008
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$309,766	$207,681	$5,863	$7,861	$636
Property, plant and equipment, net	$8,479,977	$5,389,424	$4,733,865	$2,433,643	$3,175,559
Total assets	$9,790,731	$6,219,609	$5,231,448	$2,780,317	$3,655,058
Total debt	$4,301,083	$2,814,176	$2,909,086	$2,578,938	$2,375,316
Total equity	$3,862,455	$2,548,950	$1,547,483	$(195,905)	$793,551
Total liabilities and equity	$9,790,731	$6,219,609	$5,231,448	$2,780,317	$3,655,058

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

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

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

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

Overview

SandRidge 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.

2012 Operational Highlights

Operational highlights for 2012 include the following:

- Acquired properties in the Gulf of Mexico during the second quarter of 2012 for a total of approximately $1.3 billion. These acquisitions significantly expanded the Company's presence in the Gulf of Mexico and contributed production of approximately 7.0 MMBoe in 2012.
- Drilled 396 wells in the Mid-Continent area during 2012. Mid-Continent properties contributed approximately 11.0 MMBoe, or 32.9%, of the Company's total production in 2012 compared to approximately 4.9 MMBoe, or 20.9%, in 2011.
- Increased oil production in 2012 by 6.1 MMBbls, or 51.8%, from 2011. Oil production comprised 53.5% of total production in 2012 compared to 50.6% of total production in 2011.

2013 Developments and Outlook

On February 26, 2013, the Company closed the sale of its Permian Properties for net proceeds of $2.6 billion, subject to post-closing adjustments. The Company intends to use the sales proceeds to fund capital expenditures in the Mississippian formation and to reduce outstanding debt, as well as for general corporate purposes. Additionally, the Company settled a portion of its existing oil derivative contracts in February 2013 prior to their respective maturities to reduce volumes hedged in proportion to the anticipated reduction in daily production volumes due to the sale, which resulted in a realized loss of approximately $30.0 million. The Company expects lower daily production volumes initially due to the sale of the Permian Properties; however, it expects full-year 2013 production to be generally consistent with 2012 production based on anticipated growth from the Mississippian formation as a result of increased drilling activity.

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Based on the net book value, historical costs and proved reserves as of December 31, 2012, the Company expects to incur a non-cash loss on the sale of the Permian Properties. The amount of the loss will be based on final calculations performed as of the closing date. For further discussion of the sale, including the estimated loss, see “Note 22—Subsequent Events” to the consolidated financial statements included in Item 8 of this report. Production, reserves, revenues and direct operating expenses of the Permian Properties were as follows as of and for the year ended December 31, 2012:

	2012
Production (MBoe)	8,677
Proved reserves (MBoe)	198,874
PV-10 (in millions)(1)	$3,177.6
Revenue (in millions)	$566.1
Direct operating expenses (in millions)	$130.3

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(1) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil 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 year ended December 31, 2012. 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 Permian Properties. The following table provides a reconciliation of the estimated Standardized Measure attributable to the Permian Properties to PV-10 attributable to the Permian Properties:

	December 31, 2012 (In millions)
Standardized Measure of Discounted Net Cash Flows(a)	$2,478.1
Present value of future income tax discounted at 10%	699.5
PV-10	$3,177.6

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

As a result of the divestiture of the Permian Properties and planned redemption of approximately $1.1 billion of senior notes, the Company enters 2013 with an improved liquidity position compared to a year ago. As of February 26, 2013, the Company had $2.7 billion of cash and $744.8 million available under its senior credit facility.

Results by Segment

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

Management evaluates the performance of the Company’s business segments based on income (loss) from operations, which is defined as segment operating revenues less operating expenses and depreciation, depletion, amortization and accretion. Results of these measurements provide important information to the Company about the activity, profitability and contributions of each of the Company’s lines of business. Each of the Company’s business segments results for the years ended December 31, 2012, 2011 and 2010 are discussed below.

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Exploration and Production Segment

The Company generates the majority of its consolidated revenues and cash flow from the production and sale of oil and natural gas. The Company's revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas and on the Company's ability to find and economically develop and produce oil and natural gas reserves. Prices for oil and natural gas fluctuate widely and are difficult to predict. In order to reduce the Company's exposure to these fluctuations, the Company enters into commodity derivative contracts for a portion of its anticipated future oil and natural gas production. Reducing the Company's exposure to price volatility mitigates the risk that it will not have adequate funds available for its capital expenditure programs.

The primary factors affecting the financial results of the Company's exploration and production segment are the prices the Company receives for its oil and natural gas production, the quantity of oil and natural gas it produces and changes in the fair value of commodity derivative contracts. The average annual NYMEX prices for oil and natural gas during the years ended December 31, 2012, 2011, and 2010 are shown in the following table:

	Year Ended December 31,		
	2012	2011	2010
Oil (per Bbl)	$94.10	$95.05	$79.51
Natural gas (per Mcf)	$2.75	$4.00	$4.37

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Set forth in the table below is financial, production and pricing information for the years ended December 31, 2012, 2011 and 2010.

	Year Ended December 31,		
	2012	2011	2010
Results (in thousands)			
Revenues			
Oil(1)	$1,525,896	$984,322	$494,045
Natural gas	233,386	242,472	280,718
Century Plant construction	796,323	—	—
Other	15,939	10,771	4,687
Inter-segment revenue	(403)	(265)	(259)
Total revenues	2,571,141	1,237,300	779,191
Operating expenses			
Production	480,001	324,637	238,269
Production taxes	47,210	46,069	29,170
Century Plant construction costs	796,323	—	—
Depreciation and depletion—oil and natural gas	568,029	317,246	265,914
Accretion of asset retirement obligations	28,996	9,368	9,421
Impairment	235,396	—	—
(Gain) loss on derivative contracts	(241,419)	(44,075)	50,872
Other operating expenses	138,461	62,938	97,155
Total operating expenses	2,052,997	716,183	690,801
Income from operations	$518,144	$521,117	$88,390
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—as reported(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
Average prices—including impact of derivative contract settlements			
Oil (per Bbl)(1)	$90.02	$76.41	$68.15
Natural gas (per Mcf)	$2.46	$3.27	$6.20
Total (per Boe)	$55.05	$48.35	$48.58

(1) Includes natural gas liquids.

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

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

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Revenues

Exploration and production segment revenues from oil and natural gas sales increased $532.5 million, or 43.4% in the year ended December 31, 2012 from 2011, primarily as a result of a 6.1 MMBbl, or 51.8%, increase in oil production. Natural gas production also increased 24.2 Bcf, or 35.0%; however, the average price received for natural gas production decreased by $1.01 per Mcf, or 28.9%, which more than offset the increase in natural gas production. The increase in oil and natural gas production was due to the acquisition of properties located in the Gulf of Mexico during the second quarter of 2012 combined with increased drilling in the Mid-Continent, where, during 2012, the Company completed and commenced production on 377 gross (269 net) wells.

Exploration and production segment revenues increased $458.1 million, or 58.8%, in the year ended December 31, 2011 from 2010, as a result of a 60.2% increase in oil production and a $16.32 per barrel, or 24.4%, increase in the average price received for oil production. These increases were slightly offset by a 9.1% decrease in natural gas production and an $0.18 per Mcf, or 4.9%, decrease in the average price received for natural gas production. The increase in oil production was due to the inclusion of a full year of production from the Permian Basin properties acquired in the Arena Acquisition in July 2010, and increased focus on oil drilling throughout 2010 and 2011. During 2011, the Company completed and commenced production on 943 gross (892 net) wells, substantially all of which were located in the Mid-Continent and Permian Basin. Properties acquired in the Arena Acquisition produced 4.1 MMBbls of oil, including production from additional wells drilled on the acquired properties, for the year ended December 31, 2011 compared to 1.5 MMBbls in the 2010 period after the acquisition. The decrease in natural gas production was a result of natural production declines in existing natural gas wells.

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

Operating Expenses

Production expense includes the costs associated with the Company’s exploration and production activities, including, but not limited to, lease operating expense and treating costs. Production expenses increased $155.4 million, or 47.9%, in 2012 from 2011 primarily due to operating expenses associated with oil and natural gas properties located in the Gulf of Mexico that were acquired during the second quarter of 2012 and additional oil wells located in the Mid-Continent that began producing during 2012. On a per Boe basis, production expense for 2012 was comparable to 2011, increasing $0.43, or 3.1%, to $14.31 per Boe during the year ended December 31, 2012 from $13.88 per Boe in 2011. Production expenses increased $86.4 million in 2011 from 2010 primarily due to operating expenses associated with properties acquired from Arena and additional oil wells that began producing during late 2010 and in 2011. Higher production costs were incurred on oil production compared to production costs on natural gas volumes. Total production increased 16.4% with oil production increasing 60.2% for the year ended December 31, 2011 compared to 2010.

Production taxes increased slightly for the year ended December 31, 2012 compared to 2011. Approximately 22% of the Company’s oil and natural gas production for the year ended December 31, 2012 was from production in the Gulf of Mexico, including from properties acquired during the second quarter of 2012. This production is not subject to production tax. In addition, wells drilled in the Mississippian formation in Oklahoma are part of a tax credit incentive program that reduces the combined statutory rates. Production taxes increased $16.9 million, or 57.9%, during the year ended December 31, 2011 compared to 2010 due to increased oil production, including production from properties acquired in the Arena Acquisition and newly producing wells.

Depreciation and depletion for the Company's oil and natural gas properties increased $250.8 million, or 79.1%, for the year ended December 31, 2012 from 2011. The increase was due to a 43.5% increase in the Company's combined production volume as well as an increase in the depreciation and depletion rate per Boe to $16.93 for the year ended December 31, 2012 from $13.57 per Boe in 2011, that primarily resulted from the acquisition of properties located in the Gulf of Mexico during 2012. Depreciation and depletion for the Company's oil and natural gas properties increased $51.3 million for the year ended December 31, 2011 from the same period in 2010. The increase was due to a 16.4% increase in the Company's combined production volume as well as an increase in the depreciation and depletion rate per Boe to $13.57 in 2011 from $13.24 per Boe in 2010 that resulted from the sale of oil and natural gas properties in 2011.

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

During the year ended December 31, 2012, the Company recorded a $235.4 million impairment to the carrying value of goodwill. Primarily as a result of a decrease in the Company's probable reserves as of December 31, 2012, which are one of the significant components in the determination of the fair value of the applicable reporting unit, the carrying value of the reporting unit exceeded its fair value such that the entire carrying value of the Company's goodwill was impaired. For additional information regarding the goodwill impairment, see "Note 9—Goodwill" to the Company's consolidated financial statements in Item 8 of this report.

The following table summarizes the cash settlements and valuation gain and loss on the Company's commodity derivative contracts, which are included in income from operations for the exploration and production segment for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Realized (gain) loss			
Realized gain on early settlements	$(59,466)	$(48,092)	$(114,499)
Realized loss on amended contracts	117,108	—	—
Realized (gain) loss on settlements at contractual maturity	(89,360)	98,805	(109,838)
Total realized (gain) loss	(31,718)	50,713	(224,337)
Unrealized (gain) loss	(209,701)	(94,788)	275,209
(Gain) loss on commodity derivative contracts	$(241,419)	$(44,075)	$50,872

The Company's derivative contracts are not designated as accounting hedges and, as a result, realized and unrealized gains or losses on commodity derivative contracts are recorded as a component of operating expenses. Internally, management views the settlement of such derivative contracts as adjustments to the price received for oil and natural gas production to determine "effective prices." Realized gains or losses related to settlements of derivative contracts prior to their respective contractual maturities ("early settlements") are not considered in the calculation of effective prices. The realized gain, including realized gain on early settlements, for the year ended December 31, 2012 was due primarily to lower oil prices at the time of settlement compared to the contract price for the Company's oil price swaps. These gains were partially offset by a non-cash realized loss resulting from the amendment of certain 2012 derivative contracts to contracts maturing in 2014 and 2015. The realized loss for the year ended December 31, 2011 was primarily due to higher oil prices at the time of settlement compared to the contract price for the Company's oil price swaps. Realized gains resulting from early settlements of commodity derivative contracts partially offset the realized loss for the year ended December 31, 2011. The realized gain, including realized gain on early settlements, for the year ended December 31, 2010 was primarily due to lower natural gas prices at the time of settlement compared to the contract price on the Company's natural gas price swaps.

Unrealized gain or loss on derivative contracts represents the change in fair value of open derivative contracts during the period. The unrealized gains on the Company's commodity contracts recorded during the years ended December 31, 2012 and 2011 were attributable to a decrease in average oil prices at the end of the period compared to the average oil prices at the beginning of the period, or the contract price for contracts entered into during the period. The unrealized loss on commodity contracts recorded during the year ended December 31, 2010 was attributable to an increase in average oil prices and decreases in the price differentials on the Company's natural gas basis swaps at December 31, 2010 compared to the average oil prices and price differentials at December 31, 2009 or the contract price for contracts entered into during 2010.

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

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Drilling and Oil Field Services Segment

The financial results of the Company's drilling and oil field services segment depend primarily on demand and prices that can be charged for its services. On a consolidated basis, drilling and oil field service revenues earned and expenses incurred in performing services for third parties, including third-party working interests in wells the Company operates, are included in drilling and services revenues and expenses. Drilling and oil field service revenues earned and expenses incurred in performing services for the Company's own account are eliminated in consolidation. The primary factors affecting the results of the Company's drilling and oil field services segment are the rates received on rigs drilling for third parties, the number of days rigs worked for third parties and the amount of oil field services provided to third parties.

Set forth in the table below is financial and drilling rig information regarding the drilling and oil field services segment for the years ended December 31, 2012, 2011 and 2010.

	Year Ended December 31,		
	2012	2011	2010
Results (in thousands)			
Revenues	$379,345	$390,485	$265,262
Inter-segment revenue	(262,712)	(287,187)	(236,687)
Total revenues	116,633	103,298	28,575
Operating expenses	104,722	92,957	38,545
Income (loss) from operations	$11,911	$10,341	$(9,970)
Drilling rig statistics			
Average number of operational rigs owned during the period	30.0	30.8	27.5
Average number of rigs working for third parties	9.4	10.0	4.0
Average number of days drilling for third parties	2,613	3,673	1,404
Average drilling revenue per day per rig drilling for third parties(1)	$16,919	$15,215	$14,287
Rig status as of December 31			
Working for SandRidge	14	20	20
Working for third parties(2)	10	10	9
Idle	6	—	2
Total operational	30	30	31
Non-operational(3)	1	1	—
Total rigs	31	31	31

(1) Represents revenues from the Company's rigs working for third parties, excluding stand-by revenue, divided by the total number of days such drilling rigs were used by third parties during the period, excluding revenues for related rental equipment.
(2) Includes five rigs receiving stand-by rates from third parties at December 31, 2012.
(3) Includes a rig stacked at December 31, 2012 and 2011.

Drilling and oil field services segment total revenues and operating expenses increased $13.3 million and $11.8 million, respectively, in the year ended December 31, 2012 from 2011. The increase in revenues and expenses was primarily attributable to an increase in supplies sold to, and oil field services work performed for, Company-operated wells in the Mid-Continent with higher third-party working interest percentages during the year ended December 31, 2012. While the average drilling revenue per day per rig working for third parties increased during the year ended December 31, 2012 compared to 2011, this was more than offset by a decrease in the number of days drilling for third parties. The overall increase in revenue resulted in income from operations of $11.9 million in the year ended

December 31, 2012 compared to income from operations of $10.3 million in 2011.

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Drilling and oil field services segment total revenues and operating expenses increased $74.7 million and $54.4 million, respectively, in the year ended December 31, 2011 from 2010. The increase in revenues and expenses was primarily attributable to an increase in the number of rigs working for third parties and an increase in oil field services performed for third parties during 2011. Additionally, the average daily rate received per rig working for third parties increased to $15,215 during 2011 compared to $14,287 during 2010. The increases in rigs working for third parties and the average daily rate received from third parties resulted in income from operations of $10.3 million in the year ended December 31, 2011 compared to a loss from operations of $10.0 million in 2010.

Midstream Services Segment

Midstream services segment revenues consist mostly of revenue from gas marketing, which is a very low-margin business. Midstream services are primarily undertaken to realize incremental margins on natural gas purchased at the wellhead, and provide value-added services to customers. On a consolidated basis, midstream and marketing revenues represent natural gas sold on behalf of third parties and the fees the Company charges to gather, compress and treat this natural gas. Gas marketing operating costs represent payments made to third parties for the proceeds from the sale of natural gas owned by such parties, net of any applicable margin, and actual costs the Company charges to gather, compress and treat the natural gas. In general, natural gas purchased and sold by the Company's midstream services segment is priced at a published daily or monthly index price. The primary factors affecting the results of the Company's midstream services segment are the quantity of natural gas the Company gathers, treats and markets and the prices it pays and receives for natural gas.

The Company owns and operates two gas treating plants in west Texas, which remove CO_2 from natural gas production and deliver residue gas to nearby pipelines. Occidental took ownership of and began operating Phase I and Phase II of the Century Plant during the third and fourth quarters of 2012, respectively, for the purpose of separating and removing CO_2 from the delivered natural gas stream and the Company has diverted its high CO_2 natural gas production from its two gas treating plants to the Century Plant. With the completion of the Century Plant in the fourth quarter of 2012 and prevailing low natural gas prices, the Company determined that the future use of its gas treating plants would be limited and recorded an impairment of $59.7 million in the midstream services segment in the fourth quarter of 2012.

Set forth in the table below is financial information regarding the midstream services segment for the years ended December 31, 2012, 2011 and 2010.

	Year Ended December 31,		
	2012	2011	2010
Results (in thousands)			
Revenues	$116,659	$183,912	$275,071
Inter-segment revenue	(77,824)	(118,731)	(176,549)
Total revenues	38,835	65,181	98,522
Operating expenses	111,862	78,156	94,563
(Loss) income from operations	$(73,027)	$(12,975)	$3,959
Gas Marketed			
Volumes (MMcf)	9,367	14,807	20,435
Price	$2.63	$3.88	$4.20

Midstream services segment total revenues and operating expenses, excluding impairment, for the year ended December 31, 2012 decreased $26.3 million and $23.2 million, respectively, from the same period in 2011. These decreases in revenue and operating expenses were due to a 5.4 Bcf decrease in third-party volumes the Company processed and marketed as a result of decreased natural gas production in west Texas and a decrease in natural gas prices. These decreases were partially offset by an increase in revenue from and expenses related to electrical transmission as a result of the expansion of the Company’s electrical infrastructure in the Mid-Continent in 2012. The $59.7 million impairment of the Company’s natural gas treating plants, as discussed above, resulted in a loss from operations of $73.0 million for the year ended December 31, 2012 compared to a loss from operations of $13.0 million in 2011.

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Midstream services segment total revenues and operating expenses for the year ended December 31, 2011 decreased $33.3 million and $16.4 million, respectively, from the same period in 2010. The decrease in revenues and operating costs was due to a decrease in third-party volumes the Company marketed of approximately 5.6 Bcf, a decrease in natural gas prices and a decrease in natural gas volumes processed in the Company's gas treating plants. The decrease in revenues and a $2.8 million impairment on certain midstream assets resulted in a loss from operations of $13.0 million for the year ended December 31, 2011 compared to income from operations of $4.0 million in 2010.

Consolidated Results of Operations

Revenues

The Company's consolidated revenues for the years ended December 31, 2012, 2011 and 2010 are presented in the table below.

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Revenues			
Oil and natural gas	$1,759,282	$1,226,794	$774,763
Drilling and services	116,633	103,298	28,543
Midstream and marketing	40,486	66,690	100,118
Century Plant construction	796,323	—	—
Other	18,241	18,431	28,312
Total revenues(1)	$2,730,965	$1,415,213	$931,736

(1) Includes $181.2 million, $69.6 million and $5.6 million of revenues attributable to noncontrolling interests in consolidated VIEs, after considering the effects of intercompany eliminations, for the years ended December 31, 2012, 2011 and 2010, respectively.

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

Other revenues decreased slightly for the year ended December 31, 2012 compared to 2011 as revenues from the Bullwinkle and other offshore platforms, which were acquired as part of the Dynamic Acquisition, essentially offset the decrease in CO_2 volumes sold to third parties from the Company's natural gas treating plants and CO_2 compression facilities. The Bullwinkle platform serves as a processing hub for deepwater production for third-party fields for which it receives production handling revenue. The decrease in CO_2 volumes sold to third parties was due primarily to decreased natural gas production in west Texas and the diversion of natural gas from the Company's legacy natural gas treating plants to the Century Plant. Other revenues decreased $9.9 million for the year ended December 31, 2011 from 2010. The decrease was due to lower CO_2 volumes sold to third parties from the Company's gas treating plants during the year ended December 31, 2011 compared to 2010 as a result of a decrease in natural gas production and natural gas volumes processed at the Company's gas treating plants.

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Expenses

The Company's expenses for the years ended December 31, 2012, 2011 and 2010 are presented below.

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Expenses			
Production	$477,154	$322,877	237,863
Production taxes	47,210	46,069	29,170
Drilling and services	68,227	65,654	22,368
Midstream and marketing	39,669	66,007	90,149
Century Plant construction costs	796,323	—	—
Depreciation and depletion—oil and natural gas	568,029	317,246	265,914
Depreciation and amortization—other	60,805	53,630	50,776
Accretion of asset retirement obligations	28,996	9,368	9,421
Impairment	316,004	2,825	—
General and administrative	241,682	148,643	179,565
(Gain) loss on derivative contracts	(241,419)	(44,075)	50,872
Loss (gain) on sale of assets	3,089	(2,044)	2,424
Total expenses(1)	$2,405,769	$986,200	$938,522

(1) Includes $75.4 million, $15.1 million and $1.2 million of expenses attributable to noncontrolling interests in consolidated VIEs, after considering the effects of intercompany eliminations, for the years ended December 31, 2012, 2011 and 2010, respectively.

See discussion of production expenses, production taxes, Century Plant construction costs, depreciation and depletion—oil and natural gas, accretion of asset retirement obligations, and (gain) loss on derivative contracts under "Results by Segment—Exploration and Production Segment."

Drilling and services expenses, which include operating expenses attributable to the drilling and oil field services segment and SandRidge CO_2, increased $2.6 million, or 3.9%, for the year ended December 31, 2012 compared to 2011 primarily due to an increase in supplies sold and oil field services work performed for third-party working interest owners as a result of higher third-party working interests in wells operated by the Company in the Mid-Continent during 2012. This increase was partially offset by a decrease in expenses attributable to SandRidge CO_2. Drilling and services expenses increased $43.3 million, or 193.5%, for the year ended December 31, 2011 compared to 2010 primarily due to an increase in the average number of rigs working for third parties and an increase in oil field services work performed for third parties.

Midstream and marketing expenses decreased $26.3 million, or 39.9%, during the year ended December 31, 2012 compared to 2011 due to decreased natural gas volumes purchased from third parties and processed at the Company's gas treating plants in west Texas and a decrease in natural gas prices. These decreases were slightly offset by an increase in costs associated with electrical transmission during 2012. Midstream and marketing expenses decreased $24.1 million, or 26.8%, during the year ended December 31, 2011 compared to 2010 due to decreased natural gas volumes purchased from third parties as a result of decreased natural gas production and a decrease in volumes processed at the Company's treating plants.

Depreciation and amortization—other increased $7.2 million or 13.4% for the year ended December 31, 2012 from 2011 due to an increase in other depreciable fixed assets, including drilling equipment, electrical infrastructure projects and renovations to the Company's corporate headquarters.

Impairment expense for the year ended December 31, 2012 consists primarily of a $235.4 million impairment of goodwill and a $79.3 million impairment of the Company’s gas treating plants and CO_2 compression facilities recorded in connection with the completion of the Century Plant. In 2011, the Company recorded an impairment of $2.8 million on certain midstream compressor assets as their future use was determined to be limited. See “Note 8—Impairment” and “Note 9—Goodwill” to the consolidated financial statements in Item 8 of this report for additional information regarding these impairments.

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General and administrative expenses increased $93.0 million, or 62.6% for the year ended December 31, 2012 from 2011. This increase is due primarily to a $32.3 million increase in compensation costs as a result of an increase in the number of Company employees; a $20.0 million legal settlement, as discussed in "Note 16—Commitments and Contingencies" to the consolidated financial statements in Item 8 of this report; a $19.6 million increase in legal and consulting fees, including costs associated with stockholder litigation and activism activities; $13.2 million in acquisition costs associated with the oil and natural gas properties located in the Gulf of Mexico that were acquired during the second quarter of 2012; and a $7.1 million increase in advertising expense. General and administrative expenses decreased $30.9 million, or 17.2%, to $148.6 million for the year ended December 31, 2011 from 2010. General and administrative expenses for 2010 included $17.0 million of fees incurred related to the Arena Acquisition and $18.2 million for the settlement of a dispute with certain working interest owners. The decrease in 2011 expense resulting from the absence of such costs was slightly offset by an increase in payroll expenses in the year ended December 31, 2011 due to an increase in the number of Company employees, and fees associated with the Mississippian Trust I and Permian Trust initial public offerings.

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

The Company's other income (expense), taxes and net income attributable to noncontrolling interest for the years ended December 31, 2012, 2011 and 2010 are reflected in the table below.

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Other income (expense)			
Interest expense	$(303,349)	$(237,332)	$(247,442)
Bargain purchase gain	122,696	—	—
Loss on extinguishment of debt	(3,075)	(38,232)	—
Other income, net	4,741	3,122	2,558
Total other expense	(178,987)	(272,442)	(244,884)
Income (loss) before income taxes	146,209	156,571	(251,670)
Income tax benefit	(100,362)	(5,817)	(446,680)
Net income	246,571	162,388	195,010
Less: net income attributable to noncontrolling interest	105,000	54,323	4,445
Net income attributable to SandRidge Energy, Inc.	$141,571	$108,065	$190,565

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Interest expense for the years ended December 31, 2012, 2011 and 2010 consisted of the following:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Interest expense			
Interest expense on debt	$289,094	$223,461	$219,008
Amortization of debt issuance costs, discounts and premium	16,980	13,755	13,159
Dynamic Acquisition committed financing fee	10,875	—	—
Interest rate swap loss	1,189	3,168	16,540
Capitalized interest	(14,789)	(3,052)	(1,265)
Total interest expense	$303,349	$237,332	$247,442

Interest expense increased $66.0 million for the year ended December 31, 2012 compared to 2011, primarily as a result of issuances of senior notes in 2012 and 2011, partially offset by a reduction in interest expense associated with senior notes repurchased and redeemed in 2012 and 2011. In addition, as a result of the Company electing to issue senior notes to fund the cash portion of the Dynamic Acquisition rather than utilize previously secured committed financing, fees associated with the committed financing of $10.9 million were fully expensed during the year ended December 31, 2012. Interest expense decreased $10.1 million for the year ended December 31, 2011 compared to 2010, primarily due to a $13.4 million decrease in the net loss on the Company’s interest rate swap. Additional decreases were due to lower average outstanding balances on the senior credit facility during 2011 and to the repurchase and redemption of certain senior notes in March 2011, partially offset by interest expense on senior notes issued in March 2011. See “Note 13—Long-Term Debt” to the consolidated financial statements included in Item 8 of this report for additional discussion of the Company’s long-term debt transactions in 2012 and 2011.

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

The Company recognized a loss on extinguishment of debt of $3.1 million for the year ended December 31, 2012 in connection with the tender offer to repurchase the Company’s Senior Floating Rate Notes in August 2012 and recognized a loss on extinguishment of debt of $38.2 million for the year ended December 31, 2011 in connection with the tender offer to repurchase and the redemption of the 8.625% Senior Notes due 2015 in March 2011. These losses represent the premium paid to purchase the notes and the unamortized debt issuance costs associated with the notes.

The Company reported an income tax benefit of $100.4 million for the year ended December 31, 2012. The benefit was primarily attributable to the release of a portion of the Company’s valuation allowance against its net deferred tax asset during the period. A net deferred tax liability of $100.3 million recorded as a result of the Dynamic Acquisition reduced the Company’s existing net deferred tax asset position, resulting in a corresponding reduction in the valuation allowance against the net deferred tax asset. During the year ended December 31, 2011, the Company completed its valuation of assets acquired and liabilities assumed related to the acquisition of Arena in order to finalize the purchase price allocation. In connection therewith, the Company recorded an additional net deferred tax liability of $7.0 million and released a corresponding portion of its previously recorded valuation allowance resulting in a deferred tax benefit. Also during 2011, the Company filed the final income tax returns for Arena and its subsidiaries resulting in a current tax provision of $0.7 million. The tax benefit of $5.8 million for the year ended December 31, 2011 is primarily comprised of the partial release of the Company’s previously recorded valuation allowance against its net deferred tax asset and the filing of the final income tax returns for Arena and its subsidiaries. The Company reported an income tax benefit of $446.7 million for the year ended December 31, 2010. The income tax benefit was primarily attributable to the release of a portion of the Company’s valuation allowance against its net deferred tax asset after the Company recorded net deferred tax liabilities related to the Arena Acquisition in July 2010.

Net income attributable to noncontrolling interest increased to $105.0 million for the year ended December 31, 2012 from $54.3 million in 2011 and $4.4 million in 2010 due to the completion of the Mississippian Trust I, Permian Trust and Mississippian Trust II initial public offerings in April 2011, August 2011 and April 2012, respectively. Net income attributable to noncontrolling interest reflects the portion of net income attributable to beneficial interests of the Royalty Trusts held by third parties.

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Liquidity and Capital Resources

The Company's primary sources of liquidity and capital resources are cash flows from operating activities, existing cash balances, funding commitments from third parties for drilling carries, the issuance of equity and debt securities in the capital markets, availability of borrowings under the senior credit facility and proceeds from sales or other monetizations of assets. As described in Item 1 "Business—2012 Recent Developments," the Company raised approximately $2.8 billion, net of related fees and adjustments, through a royalty trust offering, asset sales and monetizations and senior note issuances during 2012, and also sold a portion of its Mississippian Trust I and Permian Trust common units in 2012 for proceeds of approximately $139.4 million. Additionally, as described in Item 1 "Business—2012 Developments," the Company received proceeds of approximately $2.6 billion, subject to post-closing adjustments, in February 2013 for the sale of its Permian Properties.

The Company's primary uses of capital are expenditures related to its oil and natural gas properties, such as costs related to the drilling and completion of wells, including to fulfill its drilling commitments to the Royalty Trusts, the acquisition of oil and natural gas properties and other fixed assets, the payment of dividends on its outstanding convertible perpetual preferred stock, interest payments on its outstanding debt and from time to time, the redemption or repurchase of senior notes. The Company maintains access to funds that may be needed to meet capital funding requirements through its senior credit facility.

The Company's 2013 budget for capital expenditures, including expenditures related to the Company's drilling programs for the Royalty Trusts, is approximately $1.75 billion. The majority of the Company's capital expenditures are discretionary and could be curtailed if the Company's cash flows decline from expected levels or if the Company is unable to obtain capital on attractive terms. The Company and one of its wholly owned subsidiaries have entered into development agreements with the Mississippian Trust I, Permian Trust and Mississippian Trust II that obligate the Company to drill, or cause to be drilled, a specified number of wells within specific areas of mutual interest for each trust by December 31, 2015, March 31, 2016 and December 31, 2016, respectively. Additionally, production targets contained in certain gathering and treating arrangements require the Company to incur capital expenditures or make associated shortfall payments. See additional discussion of these commitments under "Contractual Obligations and Off-Balance Sheet Arrangements."

The Company depends on cash flows from operating activities, funding commitments from third parties for drilling carries and the availability of borrowings under its senior credit facility to fund its capital expenditures. Additionally, the Company may use proceeds from the issuance of equity and debt securities in the capital markets and from sales or other monetizations of assets to fund its capital expenditures. Based on current cash balances (including proceeds from the sale of the Permian Properties), anticipated oil and natural gas prices and production, commodity derivative contracts in place, and funding commitments from third parties for drilling carries, the Company expects to be able to fund its planned capital expenditures budget, debt service requirements and working capital needs for 2013. However, a substantial or extended decline in oil or natural gas prices could have a material adverse effect on the Company's financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced, which could adversely impact the Company's ability to comply with the financial covenants under its senior credit facility, which in turn would limit borrowings to fund capital expenditures. The Company may increase or decrease planned capital expenditures depending on oil and natural gas prices, the availability of capital through asset sales and the issuance of additional equity or long-term debt.

The Company's revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, each of which depend on numerous factors beyond the Company's control such as economic conditions, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile and may be subject to significant fluctuations in the future. The Company's derivative arrangements serve to mitigate a portion of the effect of this price volatility on its cash flows, and while fixed price swap contracts are in place for the majority of expected oil production for 2013, fixed price swap contracts are in place for only a portion of expected oil production for 2014 and 2015. No fixed price swap contracts are in place for any of the Company’s future natural gas production or for its oil production beyond 2015.

As an alternative to borrowing under its senior credit facility, the Company may choose to issue long-term debt or equity in the public or private markets, or both. In addition, the Company may from time to time seek to retire or purchase its outstanding securities through cash purchases and/or exchanges in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, the Company’s liquidity requirements, contractual restrictions and other factors.

As of December 31, 2012, the Company's cash and cash equivalents were $309.8 million, including $8.5 million attributable to the Company's consolidated VIEs which is available to satisfy only obligations of the VIEs. The Company had approximately $4.3 billion in total debt outstanding and $30.2 million in outstanding letters of credit with no amount outstanding under its senior credit facility at December 31, 2012. As of and for the year ended December 31, 2012, the Company was in compliance with applicable covenants under its senior credit facility and senior notes. As of February 26, 2013, the Company's cash and cash equivalents were approximately $2.7 billion, including $84.1 million attributable to the Company's consolidated VIEs. Additionally, there was no amount outstanding under the Company's senior credit facility and $30.2 million in outstanding letters of credit.

Working Capital

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

At December 31, 2012, the Company had a working capital deficit of $27.6 million compared to $257.7 million at December 31, 2011. Current assets and current liabilities at December 31, 2012 each included a $255.0 million escrow deposit received in conjunction with the agreement to sell the Permian Properties. This deposit had no impact on working capital at December 31, 2012. Excluding the escrow deposit, current assets increased $446.0 million at December 31, 2012, compared to current assets at December 31, 2011, primarily due to a $102.1 million increase in cash and cash equivalents, a $239.2 million increase in accounts receivable and a $67.0 million increase in the net asset position on the Company's current derivative contracts. The increase in cash and cash equivalents is primarily due to net proceeds received from the issuance of the 7.5% Senior Notes due 2023 and the additional 7.5% Senior Notes due 2021 after funding the tender offer for, and subsequent redemption of, the Senior Floating Rate Notes. The increase in accounts receivable is due to an increase in amounts due from working interest partners, as a result of higher third-party working interest percentages attributable to Company-operated wells in the Mid-Continent, increased drilling activity and oil and natural gas sales in the Mid-Continent and Permian Basin and increased oil and natural gas sales in the Gulf of Mexico as a result of the Gulf of Mexico properties acquired in April 2012. The increase in the Company's asset position on its current derivative contracts is due to a decrease in oil prices from December 31, 2011. Excluding the escrow deposit, current liabilities increased $216.0 million, primarily due to a $259.8 million increase in accounts payable and accrued expenses as a result of increased drilling activity and the Gulf of Mexico properties acquired in 2012, and an $85.6 million increase in the Company's current asset retirement obligations due to plugging and abandonment obligations in the Gulf of Mexico expected to be settled within one year. These increases were partially offset by a $100.6 million decrease in the Company's current liability position on its derivative contracts as a result of settlements and decreased oil prices from December 31, 2011 and a $27.8 million decrease in billings and estimated contract loss in excess of costs incurred as a result of additional costs incurred on the Century Plant construction project.

The Company expects to fund its planned capital expenditures budget, debt service requirements and working capital needs for 2013 with its existing cash balances (including proceeds from the sale of the Permian Properties), cash flows from operating activities and funding commitments from third parties for drilling carries. A significant portion of the Company's 2013 capital expenditures budget is discretionary and can be curtailed, if necessary, based on oil and natural gas prices and the availability of the sources of funds described above.

Cash Flows

The Company’s cash flows for the years ended December 31, 2012, 2011 and 2010 are presented in the following table and discussed below:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Cash flows provided by operating activities	$783,160	$458,954	$380,894
Cash flows used in investing activities	(2,555,945)	(902,329)	(953,519)
Cash flows provided by financing activities	1,874,870	645,193	570,627
Net increase (decrease) in cash and cash equivalents	$102,085	$201,818	$(1,998)

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Cash Flows from Operating Activities

The Company's operating cash flow is mainly influenced by the prices the Company receives for its oil and natural gas production; the quantity of oil and natural gas it produces; settlements on derivative contracts; and third-party demand for its drilling rigs and oil field services and the rates it is able to charge for these services.

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

Net cash provided by operating activities for the year ended December 31, 2011 increased compared to 2010 due primarily to an increase in oil sales as a result of increased oil production and prices received for oil production, partially offset by a decrease in natural gas sales as a result of decreased natural gas production and the realized loss on the Company's commodity derivative contracts in 2011 compared to the realized gain in 2010.

Cash Flows from Investing Activities

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

Cash flows used in investing activities increased for the year ended December 31, 2012 from 2011 due to the acquisitions of oil and natural gas properties located in the Gulf of Mexico during the second quarter of 2012, and an increase in capital expenditures as a result of the continued development of the Company's oil properties, primarily in the Mid-Continent. These amounts were partially offset by proceeds from the sale of assets, including the sale of working interests to Repsol and the sale of the Company's tertiary recovery properties during the year ended December 31, 2012. Proceeds from the sale of assets totaled $431.2 million in the year ended December 31, 2012 compared to $859.4 million in the same period in 2011.

Cash flows used in investing activities decreased in the year ended December 31, 2011 from 2010 due to increased proceeds from the sale of assets during the period, partially offset by an increase in capital expenditures, primarily for the continued development of the Company's oil and natural gas properties. Proceeds from asset sales, including the sale of working interests to Atinum, during 2011 totaled $859.4 million compared to $205.0 million in 2010.

Capital Expenditures. The Company's capital expenditures, on an accrual basis, by segment are summarized below:

	Year Ended December 31,		
	2012	2011	2010
	(In thousands)		
Capital expenditures			
Exploration and production	$1,951,490	$1,697,691	$1,018,699
Drilling and oil field services	27,527	25,674	31,658
Midstream services	80,413	38,514	48,401
Other	114,552	54,615	21,661
Capital expenditures, excluding acquisitions	2,173,982	1,816,494	1,120,419
Acquisitions(1)	840,740	34,628	138,428
Total	$3,014,722	$1,851,122	$1,258,847

(1) Includes only the cash portion of the acquisitions.

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Cash Flows from Financing Activities

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

The Company's cash flow provided by financing activities increased for the year ended December 31, 2011 compared to 2010. Cash provided by financing activities during 2011 was primarily comprised of $880.6 million of net proceeds from the issuance of the 7.5% Senior Notes due 2021 and $917.5 million of net proceeds from the conveyance of royalty interests to the Mississippian Trust I and the Permian Trust. These amounts were partially offset by the purchase and redemption of $650.0 million aggregate principal amount of the 8.625% Senior Notes due 2015, as well as the premium paid of $30.3 million in connection with the purchase and redemption of the 8.625% Senior Notes due 2015, $340.0 million of net repayments under the senior credit facility, $60.2 million of noncontrolling interest distributions and $56.7 million of dividends paid on the Company's convertible perpetual preferred stock.

Indebtedness

Long-term debt consists of the following at December 31, 2012 (in thousands):

9.875% Senior Notes due 2016, net of $8,843 discount	$356,657
8.0% Senior Notes due 2018	750,000
8.75% Senior Notes due 2020, net of $5,873 discount	444,127
7.5% Senior Notes due 2021, including premium of $4,328	1,179,328
8.125% Senior Notes due 2022	750,000
7.5% Senior Notes due 2023, net of $4,029 discount	820,971
Total debt	$4,301,083

The indentures governing the senior notes referred to above contain covenants imposing certain restrictions on the Company's activities, including, but not limited to, limitations on the incurrence of indebtedness, payment of dividends, investments, asset sales, certain asset purchases, transactions with related parties and consolidations or mergers.

Senior Credit Facility. The amount the Company may borrow under its senior credit facility is limited to a borrowing base, and is subject to periodic redeterminations. The Company pays a 0.5% commitment fee on any available portion of the senior credit facility. The borrowing base is determined based upon the discounted present value of future cash flows attributable to the Company's proved reserves. Because the value of the Company's proved reserves is a key factor in determining the amount of the borrowing base, changing commodity prices and the Company's success in developing reserves may affect the borrowing base. The senior credit facility matures in March 2017.

On March 29, 2012, the senior credit facility was amended and restated to, among other things, (a) increase the borrowing base to $1.0 billion from $790.0 million, (b) allow for the incurrence or issuance of additional debt (including up to $750.0 million of unsecured debt to finance the cash portion of the Dynamic purchase price and the related costs and expenses), (c) permit the Company to designate certain of its subsidiaries as unrestricted subsidiaries, and (d) effective on and after June 30, 2012, establish the financial covenants as maintaining agreed upon levels for

(i) ratio of total net debt to EBITDA, which may not exceed 4.5:1.0 at each quarter end, calculated using the last four completed fiscal quarters and (ii) ratio of current assets to current liabilities, which must be at least 1.0:1.0 at each quarter end. If no amounts are drawn under the senior credit facility when calculating the ratio of total net debt to EBITDA, the Company’s debt is reduced by its cash balance in excess of $10.0 million. In the current ratio calculation, any amounts available to be drawn under the senior credit facility are included in current assets, and unrealized assets and liabilities resulting from mark-to-market adjustments on the Company’s derivative contracts are disregarded.

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In August 2012, the borrowing base was reduced to $775.0 million from $1.0 billion as a result of the issuance of 7.5% Senior Notes due 2023 and additional 7.5% Senior Notes due 2021, as described below. The Company's borrowing base is redetermined in April and October of each year, and was reaffirmed at $775.0 million in October 2012. The impact of the sale of the Permian Properties on the Company's borrowing base will be assessed during the next regularly scheduled redetermination in April 2013.

At December 31, 2012, the Company had no amount outstanding under the senior credit facility and $30.2 million in outstanding letters of credit, which reduced the availability under the senior credit facility to $744.8 million at December 31, 2012. As of and during the year ended December 31, 2012, the Company was in compliance with all applicable financial covenants under the senior credit facility.

Senior Notes. 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 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.

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 used to fund the Company's tender offer for, and subsequent redemption of, its Senior Floating Rate Notes, discussed below, and for funding the Company's capital expenditures and for general corporate purposes.

In August 2012, the Company completed a cash tender offer to purchase any and all of the outstanding $350.0 million aggregate principal amount of its Senior Floating Rate Notes. The Company purchased approximately 94.3%, or $329.9 million, of these notes in the tender offer. In September 2012, the Company redeemed the remaining outstanding $20.1 million aggregate principal amount of its Senior Floating Rate Notes.

In November 2012, the Company exchanged the 8.125% Senior Notes due 2022, the 7.5% Senior Notes due 2023 and the additional 7.5% Senior Notes due 2021 for senior notes that are registered under the Securities Act. These exchange offers did not result in the incurrence of any additional indebtedness.

In February 2013, the Company initiated a process to redeem its 9.875% Senior Notes due 2016 and its 8.0% Senior Notes due 2018. As of February 26, 2013, there was approximately $1.1 billion in aggregate principal amount of such notes outstanding. The Company intends to use a portion of the proceeds received from the sale of the Permian Properties to redeem these senior notes.

For more information about the senior credit facility and senior notes, see "Note 13—Long-Term Debt" to the consolidated financial statements included in Item 8 of this report. For information on the future maturities of the Company's long-term debt, see the table below under Contractual Obligations and Off-Balance Sheet Arrangements.

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Contractual Obligations and Off-Balance Sheet Arrangements

As of December 31, 2012, the Company had contractual payment obligations under open gas gathering agreements, open transportation and throughput agreements, open drilling and hydraulic fracturing commitments, operating lease agreements and variable interests held in VIEs. These commitments are not recorded in the accompanying consolidated balance sheets.

A summary of the Company’s contractual obligations as of December 31, 2012 is provided in the following table (in thousands):

	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Long-term debt obligations(1)	$6,986,115	$346,406	$692,811	$999,760	$4,947,138
Gas gathering agreement(2)	352,825	42,634	84,513	83,903	141,775
Transportation and throughput agreements	96,067	26,653	32,648	22,661	14,105
Third-party drilling rig and hydraulic fracturing agreements(3)	87,381	44,229	43,152	—	—
Asset retirement obligations	498,410	118,504	110,280	88,840	180,786
Operating leases and other	26,990	7,386	8,075	4,669	6,860
Total	$8,047,788	$585,812	$971,479	$1,199,833	$5,290,664

(1) Includes interest on long-term debt.

(2) Consists of a gas gathering agreement to deliver certain minimum volumes of natural gas to PGC, an unconsolidated variable interest entity, through June 30, 2029.

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

Restricted Deposits. The Company maintains deposits in bank trust and escrow accounts as required by BOEM, BSEE, surety bond underwriters, purchase agreements or other settlement agreements to satisfy its eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use.

The Company received a $255.0 million escrow deposit with respect to the sale of the Permian Properties pending at December 31, 2012. The deposit was considered restricted until the transaction closed in February 2013.

Employee Deferred Compensation. The Company maintains a non-qualified deferred compensation plan that allows eligible highly compensated employees to elect to defer income exceeding the IRS annual limitations on qualified 401(k) retirement plans. Any assets placed in trust by the Company to fund future obligations of this plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the Company with respect to their deferred compensation in the plan. The Company had an obligation to the participants for their plan assets of $19.0 million as of December 31, 2012. Amounts are distributed to participating employees in accordance with the plan guidelines.

Development Agreements with Royalty Trusts. The Company’s development agreements with the Mississippian Trust I, Permian Trust and Mississippian Trust II obligate the Company to drill, or cause to be drilled, a specified number of wells within an area of mutual interest for each trust by December 31, 2015, March 31, 2016 and December 31, 2016, respectively. The estimated cost to fulfill the drilling obligations remaining at December 31, 2012 totaled approximately $415.0 million.

Treating Agreement Commitment. Under an agreement with Occidental, the Company is required to deliver a total of approximately 3,200 Bcf of CO_2 through December 31, 2042, and is required to compensate Occidental to the extent certain minimum annual CO_2 volume requirements are not met. Based upon current natural gas production levels, the Company expects to accrue between approximately $29.5 million and $36.0 million at December 31, 2013 for amounts related to the Company's anticipated shortfall in meeting its 2013 annual delivery obligations. 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; however, curtailed drilling due to continued low natural gas prices may result in additional shortfall payments in future periods.

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Consent Solicitation

TPG-Axon currently is soliciting the written consent of our stockholders to certain actions, including the replacement of the Company’s Board of Directors with TPG-Axon’s 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 consent solicitation period ends on March 15, 2013, unless at some time before such date TPG-Axon receives consents from holders of a majority of our outstanding shares of common stock on the record date. The Company’s business, operating results or financial condition could be adversely affected by TPG-Axon’s consent solicitation because, among other things:

- while it is pending, it creates uncertainty that could result in the loss of potential business opportunities and may make it more difficult to attract and retain qualified personnel;
- it has spurred follow-on litigation that can be costly to defend;
- if successful, 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; and
- if successful, it could result in a “change in control” that would constitute a default under the senior credit facility and require the Company to offer to repurchase its senior notes.

Stockholder Receivable

On November 9, 2012, Tom L. Ward and the Company entered into a settlement agreement with a stockholder plaintiff relating to a third-party claim under Section 16(b) of the Exchange Act. The claim was filed in December 2010 and related to certain transactions involving Company common stock by Mr. Ward in 2008 and 2009. The settlement agreement finds no liability or other wrongdoing under Section 16(b) regarding the transactions in question. Under the settlement agreement, Mr. Ward agreed to pay to the Company $5.0 million in four installments over four years commencing October 2013 and to waive his rights under his indemnification agreement with the Company with respect to this Section 16(b) action. The Company agreed to pay the fees of the plaintiff’s lawyers and paid Mr. Ward’s legal expenses as required under his indemnification agreement.

Based on the nature of the settlement as well as Mr. Ward’s position as an officer of the Company, a $5.0 million receivable was recorded as a component of additional paid-in capital as of December 31, 2012.

Valuation Allowance

In 2008 and 2009, the Company recorded full cost ceiling impairments totaling $3.5 billion on its oil and natural gas assets, resulting in the Company being in a net deferred tax asset position. Management considered all available evidence and concluded that it was more likely than not that some or all of the deferred tax assets would not be realized and established a valuation allowance against the Company’s net deferred tax asset in the period ending December 31, 2008. This valuation allowance has been maintained since 2008. See “Note 19—Income Taxes” to the consolidated financial statements included in Item 8 of this report for more discussion on the establishment of the valuation allowance against the Company’s net deferred tax asset.

Management continues to closely monitor all available evidence in considering whether to maintain a valuation allowance on its net deferred tax asset. Factors considered are, but not limited to, the reversal periods of existing deferred tax liabilities and deferred tax assets, the historical earnings of the Company and the prospects of future earnings. While the Company’s earnings have been trending upward, the Company’s 36-month cumulative earnings remained a loss through the quarter ending September 30, 2012, but turned positive for the 36-month period ending December 31, 2012. However, such positive earnings are not a definitive factor in determining to release a valuation allowance as other available evidence should be considered. For purposes of the valuation allowance analysis, “earnings” is defined as pre-tax earnings as adjusted for permanent tax adjustments.

During the quarter ended December 31, 2012, the Company announced the sale of the Permian Properties, which closed on February 26, 2013. See “Note 22—Subsequent Events” to the consolidated financial statements included in Item 8 of this report for discussion of the sale of the Permian Properties. While this transaction had not yet closed at December 31, 2012, it is appropriate to place some weight on the impact of such a future transaction for purposes of the valuation allowance analysis. Based on net book value, historical costs and proved reserves as of December 31, 2012, the Company has calculated an estimated loss on the sale of approximately $450.0 million. This loss is expected to cause the Company to revert to negative earnings for the 36-month period ending March 31, 2013. However, the book loss of approximately $450.0 million and the resulting negative earnings for the 36-month period ending March 31, 2013 may change materially based on final calculations performed as of the closing date and actual results of the period. Management has taken into account the current expectation of reverting to a cumulative negative earnings position for the 36-month period ending March 31, 2013 in its decision to maintain the valuation allowance against its net deferred tax asset.

In recent years, the Company has experienced significant earnings volatility due to substantial changes in the market price of natural gas. In 2008, the Company's earnings were primarily derived from natural gas sales and during 2008 and 2009 the market price of natural gas declined significantly. Since 2009, natural gas prices have remained relatively low. In 2009, the Company engaged in a strategy to change its focus from the exploration and production of natural gas to that of oil based on the view that natural gas prices would remain under long-term pressure due to the continued drilling in gas focused plays and that oil would provide a more stable revenue stream for the Company over the long-term. As a result of this strategy, the Company's revenues are now primarily derived from oil sales and the Company continues to take additional steps to further ensure stockholder value and future profitability.

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

In evaluating whether to release all or a portion of the valuation allowance against its net deferred tax asset, the Company concluded that despite positive earnings for the current period, the objectively verifiable negative evidence of cumulative negative earnings in recent years, along with the current expectation of reverting to a negative earnings position for the 36-month period ending March 31, 2013, outweighs the subjective positive evidence of the general upward trend in recent earnings continuing through the prospects of future earnings. Accordingly, the Company has not changed its judgment regarding the need for a full valuation allowance against its net deferred tax asset. However, a continued and sustained increase in the Company's profitability could lead to the reversal of its valuation allowance on its net deferred tax asset in the near future. The valuation allowance against the Company's net deferred tax asset at December 31, 2012 of $496.6 million was reduced during the year ended December 31, 2012 by $100.3 million as a result of the net deferred tax liability recorded as part of the Dynamic Acquisition. See "Note 3—Acquisitions and Divestitures" to the consolidated financial statements included in Item 8 of this report for further information on the Dynamic Acquisition. The amount of the potential release of the valuation allowance and corresponding income tax benefit depend on many factors including, but not limited to, additional purchase accounting entries related to the Dynamic Acquisition, future potential acquisitions and divestitures, the results of current year operations and the prospects of future earnings.

Additionally, the Company has valuation allowances totaling $60.7 million against specific deferred tax assets for which management has determined it is more likely than not that such deferred tax assets will not be realized for various reasons. The valuation allowance against these specific deferred tax assets would not be impacted by the foregoing discussion.

Critical Accounting Policies and Estimates

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

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Derivative Financial Instruments. To manage risks related to price fluctuations in oil and natural gas prices and changes in interest rates, the Company enters into oil and natural gas derivative contracts and interest rate swaps.

The Company recognizes its derivative instruments as either assets or liabilities at fair value with changes in the derivative's fair value being recognized in earnings unless designated as a hedging instrument with specific hedge accounting criteria being met. The commodity derivative instruments that the Company utilizes are primarily to manage the price risk attributable to its expected oil and natural gas production. The Company has elected not to designate price risk management activities as accounting hedges under applicable accounting guidance, and, accordingly, accounts for its commodity derivative contracts at fair value with changes in fair value reported currently in earnings. The Company also utilizes derivatives to manage its exposure to variable interest rates. None of the Company's derivatives were designated as hedging instruments during 2012, 2011 and 2010. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract. The related cash flow impact of the Company's derivative activities are reflected as cash flows from operating activities unless the derivative contract contains a significant financing element, in which case, cash settlements are classified as cash flows from financing activities in the consolidated statement of cash flows.

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

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

Proved Reserves. Approximately 97.6% of the Company's reserves were estimated by independent petroleum engineers for the year ended December 31, 2012. Estimates of proved reserves are based on the quantities of oil and natural gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond the Company's control. Estimating reserves is a complex process and relies on assumptions and subjective interpretations of available geologic, geophysical, engineering and production data, and the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, as a result of volatility and changing market conditions, commodity prices and future development costs will change from period to period, causing estimates of proved reserves to change, as well as causing estimates of future net revenues to change. For the years ended December 31, 2012, 2011 and 2010, the Company revised its proved reserves from prior years' reports by approximately (112.0) MMBoe, (36.8) MMBoe and 157.7 MMBoe, respectively, due to market prices during or at the end of the applicable period, production performance indicating more (or less) reserves in place, larger (or smaller) reservoir size than initially estimated or additional proved reserve bookings within the original field boundaries. Estimates of proved reserves are key components of the Company's most significant financial estimates involving its rate for recording depreciation and depletion on oil and natural gas properties and its full cost ceiling limitation. These revisions may be material and could materially affect the Company's future depreciation and depletion expenses.

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

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

Impairment of Oil and Natural Gas Properties. In accordance with full cost accounting rules, capitalized costs are subject to a limitation. The capitalized cost of oil and natural gas properties, net of accumulated depreciation, depletion and impairment, less related deferred income taxes, may not exceed an amount equal to the present value of future net revenues from proved oil and natural gas reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less related tax effects (the “ceiling limitation”). The Company calculates its full cost ceiling limitation using the 12-month average oil and natural gas prices for the most recent 12 months as of the balance sheet date and adjusted for “basis” or location differential, held constant over the life of the reserves. If capitalized costs exceed the ceiling limitation, the excess must be charged to expense. Once incurred, a write-down is not reversible at a later date. There were no full cost ceiling impairments recorded during 2012, 2011 or 2010.

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

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

In conjunction with the Company's substantial completion of the Century Plant and associated compression and pipeline facilities, and resulting diversion of the Company's high CO_2 natural gas production from its legacy gas treating plants to the Century Plant, the Company evaluated its gas treating plants and CO_2 compression facilities for impairment. 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 limited, and accordingly, recorded a $79.3 million impairment of its gas treating plants and CO_2 compression facilities in the fourth quarter of 2012. The fair value of the assets was estimated using a discounted cash flow approach. Significant judgments involved in estimating future cash flows of the gas treating plants and CO_2 compression facilities include projected levels of natural gas production, the prices of treating services and CO_2 sales and operating costs, all of which are subject to change. See "Note 8—Impairment" to the consolidated financial statements included in Item 8 of this report for a discussion of the Company's impairments.

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Goodwill. The Company’s goodwill represents the excess of the consideration paid over the fair value of identifiable net assets acquired in the Arena Acquisition. Goodwill is not amortized, but rather tested annually for impairment. The Company performs its annual goodwill impairment test as of July 1 and between annual evaluations if events or circumstances exist that would more-likely-than-not reduce the fair value of the reporting unit below its carrying amount. Since quoted market prices are not available for the Company’s reporting units, fair value is estimated based upon a discounted cash flow approach, the most significant judgments of which include determining the reporting unit’s anticipated future cash flows, primarily based on projected oil and natural gas revenues, operating expenses and capital expenditures, which are then discounted using an industry based weighted average cost of capital rate to estimate the fair value for the reporting unit. The reporting unit’s future cash flows are estimated based on a number of variables which are subject to change, including proved reserves and risk adjusted unproved reserves attributable to the reporting unit, estimated oil and natural gas sales using estimated quantities of oil and natural gas reserves and estimates of market prices considering forward commodity price curves at the measurement date and operating and development costs.

The Company’s annual evaluation of goodwill was completed as of July 1, 2012 with no impairment indicated. The Company’s estimate of fair value exceeded the book value of the reporting unit in the Company’s impairment test, such that even if the estimated fair value used in the Company’s impairment test was reduced by 10%, no impairment would have resulted. The Company also monitors potential impairment indicators throughout the year. Such indicators could include, but are not limited to (1) a significant or sustained decrease in oil and natural gas prices, (2) a significant adverse change in the economic or business climate, (3) an adverse action or assessment by a regulator and (4) the likelihood that a reporting unit or a significant portion of a reporting unit will be sold or otherwise disposed.

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

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

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

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

The Company accounts for its two construction contracts, discussed in "Note 12—Construction Contracts" to the consolidated financial statements included in Item 8 of this report, using the completed-contract method, under which contract revenues and costs are recognized when work under the contract is completed or substantially completed and assets have been transferred. In the interim, costs incurred on and billings related to contracts in process are accumulated on the balance sheet. Contract gains or losses are recorded as development costs within the Company's oil and natural gas properties as part of the full cost pool. Contract losses are recorded at the time it is determined that a loss will be incurred. Contract gains, if any, are recorded upon substantial completion of construction.

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The Company recognizes revenues and expenses generated from daywork and footage drilling contracts as the services are performed as the Company does not bear the risk of completion of the well. The Company may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one market to another are recognized over the term of the related drilling contract. The contract terms typically range from one month to two years.

In general, natural gas purchased and sold by the midstream business is priced at a published daily or monthly index price. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Revenues are recognized upon delivery of natural gas to customers and/or when services are rendered, pricing is determined and collectability is reasonably assured. Revenues from third-party midstream services are presented on a gross basis, as the Company acts as a principal by taking ownership of the natural gas purchased and taking responsibility of fulfillment for natural gas volumes sold. Revenue from sales of CO2 is recognized when the product is delivered to the customer.

Income Taxes. Deferred income taxes are recorded for temporary differences between financial statement and income tax basis. Temporary differences are differences between the amounts of assets and liabilities reported for financial statement purposes and their tax basis. Deferred tax assets are recognized for temporary differences that will be deductible in future years' tax returns and for operating loss and tax credit carryforwards. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred tax assets will not be realized. Deferred tax liabilities are recognized for temporary differences that will be taxable in future years' tax returns. As of December 31, 2012, the Company continued to have a full valuation allowance against its net deferred tax asset. The valuation allowance serves to reduce the tax benefits recognized from the net deferred tax asset to an amount that is more likely than not to be realized based on the weight of all available evidence.

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

Allocation of Purchase Price in Business Combinations. Accounting for the acquisition of a business requires the allocation of the purchase price to the various assets and liabilities of the acquired business and recording deferred taxes for any differences between the allocated values and tax basis of assets and liabilities. Any excess of the purchase price over the amounts assigned to assets and liabilities is recorded as goodwill.
The purchase price allocation is accomplished by recording each asset and liability at its estimated fair value. Estimated deferred taxes are based on available information concerning the tax basis of the acquired company's assets and liabilities and tax-related carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed relative to the total acquisition cost.
In estimating the fair values of assets acquired and liabilities assumed, the Company makes various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and natural gas

properties. To estimate the fair values of these properties, the Company prepares estimates of oil and natural gas reserves and factors in a discount for reserve categories based on industry factors applicable to each acquisition. The prices utilized in the reserves estimates are based upon forward commodity strip prices, after adjustment for transportation fees and regional price differentials, as of the acquisition date for the first four years and escalated for inflation beginning with the fifth year through the end of expected production. Future cash flows are discounted using an industry weighted average cost of capital rate. Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. See “Note 3—Acquisitions and Divestitures” to the consolidated financial statements included in Item 8 of this report for a discussion of the Company’s acquisitions.

New Accounting Pronouncements

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

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

General

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

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

The Company uses, and may continue to use, a variety of commodity-based derivative contracts, including fixed price swaps, collars and basis swaps. At December 31, 2012, the Company's commodity derivative contracts consisted of fixed price swaps, collars and basis swaps, which are described below:

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

The Company's oil fixed price swap transactions are settled based upon the average daily prices for the calendar month or quarter of the contract period. The Company's oil basis swap transactions are settled based upon the differential between the NYMEX or Argus West Texas Intermediate price and the Argus Louisiana Light Sweet price. The Company's two-way and three-way oil collars are settled based upon the arithmetic average of NYMEX oil prices during the calculation period for the relevant contract. The Company's natural gas fixed price swap transactions are settled based upon NYMEX prices, and the Company's natural gas basis swap transactions are settled based upon the index price of natural gas at the Waha hub, a west Texas gas marketing and delivery center, or the Houston Ship Channel. The Company's natural gas collars are settled based upon the NYMEX prices on the penultimate commodity business day for the relevant contract. Settlement for oil derivative contracts occurs in the succeeding month or quarter and natural gas derivative contracts are settled in the production month or quarter.

At December 31, 2012, the Company's open commodity derivative contracts consisted of the following:

Oil Price Swaps

	Notional (MBbls)	Weighted Average Fixed Price
January 2013 — December 2013	18,515	$96.24
January 2014 — December 2014	7,511	$92.43
January 2015 — December 2015	5,076	$83.69

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Oil Basis Swaps

	Notional (MBbls)	Weighted Average Fixed Price
January 2013 — December 2013	543	$ 13.83

Oil Collars - Two-way

	Notional (MBbls)	Collar Range	
January 2013 — December 2013	168	$80.00	— $102.50

Oil Collars - Three-way

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

Natural Gas Collars

	Notional (MMcf)	Collar Range	
January 2013 — December 2013	6,858	$3.78	— $6.71
January 2014 — December 2014	937	$4.00	— $7.78
January 2015 — December 2015	1,010	$4.00	— $8.55

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

The following table summarizes the cash settlements and valuation gains and losses on the Company's commodity derivative contracts for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Realized (gain) loss(1)	$(31,718)	$50,713	$(224,337)
Unrealized (gain) loss	(209,701)	(94,788)	275,209
(Gain) loss on commodity derivative contracts	$(241,419)	$(44,075)	$50,872

(1) The year ended December 31, 2012 includes $59.5 million of net realized gain related to early settlements of commodity derivative contracts and a $117.1 million non-cash realized loss on derivative contracts amended in January 2012. The years ended December 31, 2011 and 2010 include $48.1 million ($111.0 million realized gain and $62.9 million realized loss) and $114.5 million of realized gain, respectively, related to early settlements.

See "Note 14—Derivatives" to the consolidated financial statements included in Item 8 of this report for additional information regarding the Company's commodity derivatives.

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

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A default by the Company under its senior credit facility constitutes a default under its derivative contracts with counterparties that are lenders under the senior credit facility. The Company does not require collateral or other security from counterparties to support derivative instruments. The Company has master netting agreements with all of its derivative contract counterparties, which allows the Company to net its derivative assets and liabilities with the same counterparty. As a result of the netting provisions, the Company's maximum amount of loss under derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the derivatives. The Company's loss is further limited as any amounts due from a defaulting counterparty that is a lender under the senior credit facility can be offset against amounts owed to such counterparty under the Company's senior credit facility. As of December 31, 2012, the counterparties to the Company's open derivative contracts consisted of 15 financial institutions, 13 of which are also lenders under the Company's senior credit facility. As a result, the Company is not required to post additional collateral under derivative contracts as the majority of the counterparties to the Company's derivative contracts share in the collateral supporting the Company's senior credit facility. To secure their obligations under the derivative contracts novated by the Company, the Permian Trust and Mississippian Trust II have each given the counterparties to such contracts a lien on their royalty interest. See "Note 4—Variable Interest Entities" to the consolidated financial statements included in Item 8 of this report for additional information on the Permian Trust's and Mississippian Trust II's derivative contracts.

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

Interest Rate Risk. The Company is subject to interest rate risk on its long-term fixed and variable interest rate borrowings. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes the Company to (i) changes in market interest rates reflected in the fair value of the debt and (ii) the risk that the Company may need to refinance maturing debt with new debt at a higher rate. Variable rate debt, where the interest rate fluctuates, exposes the Company to short-term changes in market interest rates as its interest obligations on these instruments are periodically redetermined based on prevailing market interest rates, primarily the LIBOR and the federal funds rate. The Company had no outstanding variable rate debt as of December 31, 2012.

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

The following table summarizes the cash settlements and valuation gains and losses, which are included in interest expense in the Company's consolidated statements of operations, on the Company's interest rate swaps for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Realized loss	$9,243	$9,414	$8,145
Unrealized (gain) loss	(8,054)	(6,246)	8,395
Loss on interest rate swaps	$1,189	$3,168	$16,540

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Item 8. Financial Statements and Supplementary Data

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

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

Not applicable.

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Item 9A. Controls and Procedures

Disclosure Controls and Procedures. Under the supervision and with the participation of the Company’s management, including its Chief Executive Officer and Chief Financial Officer, the Company performed an evaluation of the effectiveness of the design and operation of its disclosure controls and procedures pursuant to Exchange Act Rules 13a-15 and 15d-15 as of the end of the period covered by this annual report. Based on that evaluation, the Company’s Chief Executive Officer and its Chief Financial Officer concluded that its disclosure controls and procedures were effective as of December 31, 2012 to provide reasonable assurance that the information required to be disclosed by the Company in its reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, or other persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Management’s Report on Internal Control over Financial Reporting and Report of Independent Registered Public Accounting Firm. The information required to be furnished pursuant to this item is set forth under the captions “Management’s Report on Internal Control over Financial Reporting” and “Report of Independent Registered Public Accounting Firm” in Item 8 of this report. As permitted by the SEC under the current year acquisition scope exception and described under “Changes in Internal Control over Financial Reporting” below, the scope of this evaluation excluded the Company’s newly-acquired subsidiary, Dynamic.

Changes in Internal Control over Financial Reporting. Since the acquisition of Dynamic on April 17, 2012, the Company has been aligning Dynamic’s controls to the Company’s existing control environment. As this process was ongoing as of December 31, 2012, it was not possible for the Company to perform an assessment of Dynamic’s internal control over financial reporting as of December 31, 2012. Management expects that Dynamic’s controls will be aligned and integrated into the Company’s control environment within one year of the date of the acquisition and will include Dynamic in its assessment of the effectiveness of internal control over financial reporting as of December 31, 2013. Dynamic is a wholly-owned subsidiary whose total assets and total revenues represent 20% and 13%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012.

There were no changes in the Company’s internal control over financial reporting during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

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Item 9B. Other Information

Not applicable.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2013: "Director Biographical Information," "Executive Officers," "Compliance with Section 16(a) of the Exchange Act" and "Corporate Governance Matters."

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Item 11. Executive Compensation

The information required by this item is incorporated herein by reference to the following sections of the Company’s definitive proxy statement, which will be filed no later than April 30, 2013: “Director Compensation,” “Outstanding Equity Awards” and “Executive Officers and Compensation.”

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

The information required by this item is incorporated herein by reference to the following sections of the Company’s definitive proxy statement, which will be filed no later than April 30, 2013: “Equity Compensation Plan Information” and “Security Ownership of Certain Beneficial Owners and Management.”

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Item 13. Certain Relationships and Related Transactions and Director Independence

The information required by this item is incorporated herein by reference to the following sections of the Company's definitive proxy statement, which will be filed no later than April 30, 2013: "Related Party Transactions" and "Corporate Governance Matters."

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Item 14. Principal Accounting Fees and Services

The information required by this item is incorporated herein by reference to the section captioned “Ratification of Selection of Independent Registered Public Accounting Firm” in the Company’s definitive proxy statement, which will be filed no later than April 30, 2013.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

The following documents are filed as a part of this report:
(1)Consolidated Financial Statements
Reference is made to the Index to Consolidated Financial Statements appearing on page F-1.
(2)Financial Statement Schedules
All financial statement schedules have been omitted because they are not applicable or the required information is presented in the consolidated financial statements or notes thereto.
(3)Exhibits

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate. Management has excluded Dynamic Offshore Resources, LLC ("Dynamic") from its assessment of internal control over financial reporting as of December 31, 2012 as it was acquired by the Company in a business combination during 2012. Dynamic is a wholly-owned subsidiary whose total assets and total revenues represent 20% and 13%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012.

Based on our evaluation using criteria for effective internal control over financial reporting described in Internal Control—Integrated Framework, our management concluded, that as of December 31, 2012, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2012 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

/s/ TOM L. WARD	/s/ JAMES D. BENNETT
Tom L. Ward	James D. Bennett
Chief Executive Officer and Chairman of the Board	Executive Vice President and Chief Financial Officer

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Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in stockholders' equity and cash flows present fairly, in all material respects, the financial position of SandRidge Energy, Inc. and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

As described in Management's Report on Internal Control over Financial Reporting, management has excluded Dynamic Offshore Resources, LLC (“Dynamic”) from its assessment of internal control over financial reporting as of December 31, 2012 because it was acquired by the Company in a purchase business combination during 2012. We have also excluded Dynamic from our audit of internal control over financial reporting. Dynamic is a wholly-owned subsidiary whose total assets and total revenues represent 20% and 13%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2012.

/s/ PricewaterhouseCoopers LLP
PricewaterhouseCoopers LLP

Tulsa, Oklahoma
March 1, 2013

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SandRidge Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31, 2012	2011
	(In thousands, except per share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$309,766	$207,681
Accounts receivable, net	445,506	206,336
Derivative contracts	71,022	4,066
Inventories	3,618	6,903
Costs in excess of billings	11,229	—
Prepaid expenses	31,319	14,099
Restricted deposit	255,000	—
Other current assets	15,425	2,755
Total current assets	1,142,885	441,840
Oil and natural gas properties, using full cost method of accounting		
Proved (includes development and project costs excluded from amortization of $72.4 million and $231.3 million at December 31, 2012 and 2011, respectively)	12,262,921	8,969,296
Unproved	865,863	689,393
Less: accumulated depreciation, depletion and impairment	(5,231,182)	(4,791,534)
	7,897,602	4,867,155
Other property, plant and equipment, net	582,375	522,269
Restricted deposits	27,947	27,912
Derivative contracts	23,617	26,415
Goodwill	—	235,396
Other assets	116,305	98,622
Total assets	$9,790,731	$6,219,609

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

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

	December 31, 2012	2011
	(In thousands, except per share data)	
LIABILITIES AND EQUITY		
Current liabilities		
Current maturities of long-term debt	$—	$1,051
Accounts payable and accrued expenses	766,544	506,784
Billings and estimated contract loss in excess of costs incurred	15,546	43,320
Derivative contracts	14,860	115,435
Asset retirement obligations	118,504	32,906
Deposit on pending sale	255,000	—
Total current liabilities	1,170,454	699,496
Long-term debt	4,301,083	2,813,125
Derivative contracts	59,787	49,695
Asset retirement obligations	379,906	95,210
Other long-term obligations	17,046	13,133
Total liabilities	5,928,276	3,670,659
Commitments and contingencies (Note 16)		
Equity		
SandRidge Energy, Inc. stockholders' equity		
Preferred stock, $0.001 par value, 50,000 shares authorized		
8.5% Convertible perpetual preferred stock; 2,650 shares issued and outstanding at December 31, 2012 and 2011; aggregate liquidation preference of $265,000	3	3
6.0% Convertible perpetual preferred stock; 2,000 shares issued and outstanding at December 31, 2012 and 2011; aggregate liquidation preference of $200,000	2	2
7.0% Convertible perpetual preferred stock; 3,000 shares issued and outstanding at December 31, 2012 and 2011; aggregate liquidation preference of $300,000	3	3
Common stock, $0.001 par value, 800,000 shares authorized; 491,578 issued and 490,359 outstanding at December 31, 2012 and 412,827 issued and 411,953 outstanding at December 31, 2011	476	399
Additional paid-in capital	5,233,019	4,568,856
Additional paid-in capital—stockholder receivable	(5,000)	—
Treasury stock, at cost	(8,602)	(6,158)
Accumulated deficit	(2,851,048)	(2,937,094)
Total SandRidge Energy, Inc. stockholders' equity	2,368,853	1,626,011
Noncontrolling interest	1,493,602	922,939
Total equity	3,862,455	2,548,950
Total liabilities and equity	$9,790,731	$6,219,609

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

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SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Operations

	Years Ended December 31,		
	2012	2011	2010
	(In thousands, except per share amounts)		
Revenues			
Oil and natural gas	$1,759,282	$1,226,794	$774,763
Drilling and services	116,633	103,298	28,543
Midstream and marketing	40,486	66,690	100,118
Century Plant construction	796,323	—	—
Other	18,241	18,431	28,312
Total revenues	2,730,965	1,415,213	931,736
Expenses			
Production	477,154	322,877	237,863
Production taxes	47,210	46,069	29,170
Drilling and services	68,227	65,654	22,368
Midstream and marketing	39,669	66,007	90,149
Century Plant construction costs	796,323	—	—
Depreciation and depletion—oil and natural gas	568,029	317,246	265,914
Depreciation and amortization—other	60,805	53,630	50,776
Accretion of asset retirement obligations	28,996	9,368	9,421
Impairment	316,004	2,825	—
General and administrative	241,682	148,643	179,565
(Gain) loss on derivative contracts	(241,419)	(44,075)	50,872
Loss (gain) on sale of assets	3,089	(2,044)	2,424
Total expenses	2,405,769	986,200	938,522
Income (loss) from operations	325,196	429,013	(6,786)
Other income (expense)			
Interest expense	(303,349)	(237,332)	(247,442)
Bargain purchase gain	122,696	—	—
Loss on extinguishment of debt	(3,075)	(38,232)	—
Other income, net	4,741	3,122	2,558
Total other expense	(178,987)	(272,442)	(244,884)
Income (loss) before income taxes	146,209	156,571	(251,670)
Income tax benefit	(100,362)	(5,817)	(446,680)
Net income	246,571	162,388	195,010
Less: net income attributable to noncontrolling interest	105,000	54,323	4,445
Net income attributable to SandRidge Energy, Inc.	141,571	108,065	190,565
Preferred stock dividends	55,525	55,583	37,442
Income available to SandRidge Energy, Inc. common stockholders	$86,046	$52,482	$153,123
Earnings per share			
Basic	$0.19	$0.13	$0.52
Diluted	$0.19	$0.13	$0.52
Weighted average number of common shares outstanding			
Basic	453,595	398,851	291,869
Diluted	456,015	406,645	315,349

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

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

	Convertible Perpetual Preferred Stock		Common Stock		Additional Paid-In Capital	Treasury Stock	Accumulated Deficit	Non-controlling Interest	Total
	Shares	Amount	Shares	Amount					
	(In thousands)								
Balance at December 31, 2009	4,650	$5	208,715	$203	$2,961,613	$(25,079)	$(3,142,699)	$10,052	$(195,905)
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(3,515)	(3,515)
Contributions from noncontrolling interest owners	—	—	—	—	—	—	—	306	306
Issuance of convertible perpetual preferred stock, net	3,000	3	—	—	290,701	—	—	—	290,704
Issuance of common stock in acquisition	—	—	190,280	190	1,246,144	—	—	—	1,246,334
Common stock issued under legal settlement	—	—	1,789	2	(1,835)	14,033	—	—	12,200
Purchase of treasury stock	—	—	—	—	—	(6,275)	—	—	(6,275)
Retirement of treasury stock	—	—	—	—	(11,268)	11,268	—	—	—
Stock purchase—retirement plans, net of distributions	—	—	(96)	—	2,327	2,506	—	—	4,833
Stock awards assumed in acquisition	—	—	—	—	2,152	—	—	—	2,152
Stock-based compensation	—	—	—	—	39,066	—	—	—	39,066
Stock-based compensation excess tax benefit	—	—	—	—	15	—	—	—	15
Issuance of restricted stock awards, net of cancellations	—	—	5,672	3	(3)	—	—	—	—
Net income	—	—	—	—	—	—	190,565	4,445	195,010
Convertible perpetual preferred stock dividends	—	—	—	—	—	—	(37,442)	—	(37,442)
Balance at December 31, 2010	7,650	8	406,360	398	4,528,912	(3,547)	(2,989,576)	11,288	1,547,483
Issuance of units by royalty trusts	—	—	—	—	—	—	—	917,528	917,528

Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(60,200)	(60,200)
Preferred stock issuance expense	—	—	—	—	(231)	—	—	—	(231)
Purchase of treasury stock	—	—	—	—	—	(10,834)	—	—	(10,834)
Retirement of treasury stock	—	—	—	—	(10,834)	10,834	—	—	—
Stock purchase—retirement plans, net of distributions	—	—	(405)	—	3,179	(2,611)	—	—	568
Stock-based compensation	—	—	—	—	47,778	—	—	—	47,778
Stock-based compensation excess tax benefit	—	—	—	—	53	—	—	—	53
Issuance of restricted stock awards, net of cancellations	—	—	5,998	1	(1)	—	—	—	—
Net income	—	—	—	—	—	—	108,065	54,323	162,388
Convertible perpetual preferred stock dividends	—	—	—	—	—	—	(55,583)	—	(55,583)
Balance at December 31, 2011	7,650	8	411,953	399	4,568,856	(6,158)	(2,937,094)	922,939	2,548,950
Issuance of units by royalty trust	—	—	—	—	—	—	—	587,086	587,086
Sale of royalty trust units	—	—	—	—	79,056	—	—	60,304	139,360
Distributions to noncontrolling interest owners	—	—	—	—	—	—	—	(181,727)	(181,727)
Issuance of common stock in acquisition	—	—	73,962	74	542,064	—	—	—	542,138
Purchase of treasury stock	—	—	—	—	—	(11,312)	—	—	(11,312)
Retirement of treasury stock	—	—	—	—	(11,312)	11,312	—	—	—
Stock purchase—retirement plans, net of distributions	—	—	(345)	—	2,146	(2,444)	—	—	(298)
Stock-based compensation	—	—	—	—	47,228	—	—	—	47,228
Stock-based compensation excess tax benefit	—	—	—	—	(16)	—	—	—	(16)
Issuance of restricted stock awards, net of	—	—	4,789	3	(3)	—	—	—	—

cancellations									
Net income	—	—	—	—	—	—	141,571	105,000	246,571
Convertible perpetual preferred stock dividends	—	—	—	—	—	—	(55,525)	—	(55,525)
Balance at December 31, 2012	7,650	$8	490,359	$476	$5,228,019	$(8,602)	$(2,851,048)	$1,493,602	$3,862,455

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

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SandRidge Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$246,571	$162,388	$195,010
Adjustments to reconcile net income to net cash provided by operating activities			
Provision for doubtful accounts	1,735	2,511	129
Depreciation, depletion and amortization	628,834	370,876	316,690
Accretion of asset retirement obligations	28,996	9,368	9,421
Impairment	316,004	2,825	—
Debt issuance costs amortization	14,388	11,372	11,006
Amortization of discount, net of premium, on long-term debt	2,592	2,383	2,153
Bargain purchase gain	(122,696)	—	—
Loss on extinguishment of debt	3,075	38,232	—
Deferred income taxes	(100,288)	(6,986)	(447,500)
Unrealized (gain) loss on derivative contracts	(217,755)	(101,034)	283,604
Realized loss on amended derivative contracts	117,108	—	—
Realized (gain) loss on financing derivative contracts	(13,651)	6,591	—
Loss (gain) on sale of assets	3,089	(2,044)	2,424
Stock-based compensation	42,795	38,684	37,681
Other	(1,537)	155	(460)
Changes in operating assets and liabilities increasing (decreasing) cash			
Receivables	(141,534)	(61,645)	(11,480)
Inventories	3,111	(2,998)	(238)
Billings and estimated contract loss in excess of costs incurred, net	(89,003)	(11,013)	(61,180)
Other current assets	(10,649)	71	8,079
Other assets and liabilities, net	34,447	(35,773)	2,667
Asset retirement obligations	(84,361)	(16,531)	(9,234)
Accounts payable and accrued expenses	121,889	51,522	42,122
Net cash provided by operating activities	783,160	458,954	380,894
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment	(2,146,372)	(1,727,106)	(1,035,137)
Acquisitions of assets, net of cash received of $0, $0 and $39,518, respectively	(840,740)	(34,628)	(138,428)
Proceeds from sale of assets	431,167	859,405	204,951
Deposit received on pending asset sale	—	—	10,000
Refunds of restricted deposits	—	—	5,095
Net cash used in investing activities	(2,555,945)	(902,329)	(953,519)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings	1,850,344	2,033,000	2,117,914
Repayments of borrowings	(366,029)	(2,130,293)	(1,789,919)
Premium on debt redemption	(844)	(30,338)	—
Debt issuance costs	(48,538)	(20,326)	(12,540)
Proceeds from issuance of royalty trust units	587,086	917,528	—
Proceeds from the sale of royalty trust units	139,360	—	—

Noncontrolling interest distributions	(181,727)	(60,200)	(3,515)
Noncontrolling interest contributions	—	—	306
Proceeds from issuance of convertible perpetual preferred stock, net	—	(231)	290,704
Stock-based compensation excess tax benefit	(16)	53	15
Purchase of treasury stock	(14,723)	(13,796)	(7,169)
Dividends paid—preferred	(55,525)	(56,742)	(28,525)
Cash (paid) received on settlement of financing derivative contracts	(34,518)	6,538	3,356
Net cash provided by financing activities	1,874,870	645,193	570,627
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	102,085	201,818	(1,998)
CASH AND CASH EQUIVALENTS, beginning of year	207,681	5,863	7,861
CASH AND CASH EQUIVALENTS, end of year	$309,766	$207,681	$5,863

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

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SandRidge Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements

1. Summary of Significant Accounting Policies

Nature of Business. SandRidge Energy, Inc. (the “Company” or “SandRidge”) is an independent oil and natural gas company 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 in the Mid-Continent area of Oklahoma and Kansas. The Company owns and operates additional interests in the Mid-Continent, Gulf of Mexico, Permian Basin, West Texas Overthrust (“WTO”) and Gulf Coast. 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 a drilling rig business.

Principles of Consolidation. The consolidated financial statements include the accounts of the Company and its wholly owned or majority owned subsidiaries and variable interest entities (“VIEs”) for which the Company is the primary beneficiary. All significant intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications. Certain reclassifications have been made to the prior period financial statements to conform to the current period presentation. These reclassifications have no effect on the Company’s previously reported results of operations.

Use of Estimates. The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America (“GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The more significant areas requiring the use of assumptions, judgments and estimates include: oil and natural gas reserves; cash flow estimates used in impairment tests of goodwill and other long-lived assets; depreciation, depletion and amortization; asset retirement obligations; assigning fair value and allocating purchase price in connection with business combinations; income taxes; valuation of derivative instruments; and accrued revenue and related receivables. Although management believes these estimates are reasonable, actual results could significantly differ from these estimates.

Risks and Uncertainties. The Company’s revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, each of which depends on numerous factors beyond the Company’s control such as overall oil and natural gas production and inventories in relevant markets, economic conditions, the global political environment, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. The Company’s derivative arrangements serve to mitigate a portion of the effect of this price volatility on the Company’s cash flows. See Note 14 for the Company’s open oil and natural gas commodity derivative contracts.

Production targets contained in certain gathering and treating agreements require the Company to incur capital expenditures or make associated shortfall payments. Additionally, the Company has a drilling obligation to each of SandRidge Mississippian Trust I (the “Mississippian Trust I”), SandRidge Permian Trust (the “Permian Trust”) and SandRidge Mississippian Trust II (the “Mississippian Trust II”). See Note 4 for discussion of these drilling obligations.

The Company depends on cash flows from operating activities, funding commitments from third parties for drilling carries and the availability of borrowings under its senior secured revolving credit facility (the “senior credit facility”) to fund its capital expenditures. Additionally, the Company may use proceeds from the issuance of equity and debt securities in the capital markets and from sales or other monetizations of assets to fund its capital expenditures. Based on existing cash balances (including proceeds from the sale of the Permian Properties), cash flows from operating activities and funding commitments from third parties for drilling carries, the Company expects to be able to fund its planned capital expenditures budget, debt service requirements and working capital needs for 2013. However, a substantial or extended decline in oil or natural gas prices could have a material adverse effect on the Company’s financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced, which could adversely impact the Company’s ability to comply with the financial covenants under its senior credit facility, which in turn would limit further borrowings to fund capital expenditures. See Note 13 for discussion of the financial covenants in the senior credit facility.

Cash and Cash Equivalents. The Company considers all highly-liquid instruments with an original maturity of three months or less to be cash equivalents as these instruments are readily convertible to known amounts of cash and bear insignificant risk of changes in value due to their short maturity period.

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Accounts Receivable, Net. The Company has receivables for sales of oil and natural gas, as well as receivables related to the exploration and treating services for oil and natural gas. An allowance for doubtful accounts has been established based on management's review of the collectability of the receivables in light of historical experience, the nature and volume of the receivables and other subjective factors. Accounts receivable are charged against the allowance, upon approval by management, when they are deemed uncollectible. Refer to Note 6 for further information on the Company's accounts receivable and allowance for doubtful accounts.

Inventories. Inventories consist of oil field services supplies and are stated at the lower of cost or market with cost determined on an average cost basis. Inventories are shown net of a provision for obsolescence, commensurate with known or estimated exposure, of $0.3 million and $0.2 million at December 31, 2012 and 2011, respectively.

Fair Value of Financial Instruments. Certain of the Company's financial assets and liabilities are measured at fair value. Fair value represents the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The Company's financial instruments, not otherwise recorded at fair value, consist primarily of cash, trade receivables, trade payables and long-term debt. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short-term maturity of these instruments. See Note 5 for further discussion of the Company's fair value measurements.

Fair Value of Non-financial Assets and Liabilities. The Company also applies fair value accounting guidance to initially, or as events dictate, measure non-financial assets and liabilities such as business acquisitions, property, plant and equipment and asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. Fair value may be estimated using comparable market data, a discounted cash flow method, or a combination of the two. In the discounted cash flow method, estimated future cash flows are based on management's expectations for the future and include estimates of future oil and natural gas production or other applicable sales estimates, operational costs and a risk-adjusted discount rate. The Company primarily uses the present value of estimated future cash inflows and/or outflows to value its non-financial assets and liabilities when circumstances dictate determining fair value is necessary. Given the significance of the unobservable nature of a number of the inputs, these are considered Level 3 on the fair value hierarchy discussed in Note 5. See Note 3 for additional discussion of the Company's acquisitions. Additionally, the Company prepared fair value analyses of its gas treating plants and CO_2 compression facilities in 2012 as discussed further in Note 8.

Derivative Financial Instruments. To manage risks related to price fluctuations in oil and natural gas prices and changes in interest rates, the Company enters into oil, natural gas and interest rate derivative contracts.

The Company recognizes its derivative instruments as either assets or liabilities at fair value with changes in the derivative's fair value being recognized in earnings unless designated as a hedging instrument with specific hedge accounting criteria being met. The commodity derivative instruments that the Company utilizes are to manage the price risk attributable to its expected oil and natural gas production. The Company has elected not to designate price risk management activities as accounting hedges under applicable accounting guidance, and, accordingly, accounts for its commodity derivative contracts at fair value with changes in fair value reported currently in earnings. The Company also utilizes derivatives to manage its exposure to variable interest rates and has not designated its interest rate swap as a hedging instrument. As such, the interest rate swap is recorded at fair value with the change in fair value reported currently in earnings. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with the counterparty to a derivative contract. The related cash flow impact of the Company's derivative activities are reflected as cash flows from operating activities unless the derivative contract contains a significant financing element; in this case, the cash settlements for these derivatives are classified as cash flows from financing activities in the consolidated statement of cash flows. See Note 14 for further discussion of the Company's derivatives.

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Oil and Natural Gas Operations. The Company uses the full cost method to account for its oil and natural gas properties. Under full cost accounting, all costs directly associated with the acquisition, exploration and development of oil and natural gas reserves are capitalized into a full cost pool. These capitalized costs include costs of all unproved properties and internal costs directly related to the Company's acquisition, exploration and development activities and capitalized interest. The Company capitalized internal costs of $61.3 million, $37.1 million and $28.6 million to the full cost pool in 2012, 2011 and 2010, respectively. Capitalized costs are amortized using a unit-of-production method. Under this method, depreciation and depletion is computed at the end of each quarter by multiplying total production for the quarter by a depletion rate. The depletion rate is determined by dividing the total unamortized cost base plus future development costs by net equivalent proved reserves at the beginning of the quarter. Costs associated with unproved properties are excluded from the amortizable cost base until a determination has been made as to the existence of proved reserves. Unproved properties are reviewed at the end of each quarter to determine whether the costs incurred should be reclassified to the full cost pool and, thereby, subjected to amortization. The costs associated with unproved properties relate primarily to costs to acquire unproved acreage. Unproved leasehold costs are transferred to the amortization base with the costs of drilling the related well upon determination of the existence of proved reserves or upon impairment of a lease. Costs of seismic data are allocated to various unproved leaseholds and transferred to the amortization base with the associated leasehold costs on a specific project basis.
All items classified as unproved property are assessed on a quarterly basis for possible impairment or reduction in value. Properties are assessed on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of various factors, including, but not limited to, the following: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; assignment of proved reserves; and economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, all or a portion of the associated leasehold costs are transferred to the full cost pool and become subject to amortization.
Under the full cost method of accounting, total capitalized costs of oil and natural gas properties, net of accumulated depreciation, depletion and impairment, less related deferred income taxes may not exceed an amount equal to the present value of future net revenues from proved reserves, discounted at 10% per annum, plus the lower of cost or fair value of unproved properties, plus estimated salvage value, less the related tax effects (the "ceiling limitation"). A ceiling limitation calculation is performed at the end of each quarter. If total capitalized costs, net of accumulated depreciation, depletion and impairment, less related deferred taxes are greater than the ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders' equity in the period of occurrence and typically results in lower depreciation and depletion expense in future periods. Once incurred, a write-down is not reversible at a later date.
The ceiling limitation calculation is prepared using a 12-month oil and natural gas average price, as adjusted for basis or location differentials using a 12-month average, held constant over the life of the reserves ("net wellhead prices"). If applicable, these net wellhead prices would be further adjusted to include the effects of any fixed price arrangements for the sale of oil and natural gas. The Company may, from time-to-time, use derivative financial instruments to hedge against the volatility of oil and natural gas prices. Derivative contracts that qualify and are designated as cash flow hedges are included in estimated future cash flows. Historically, the Company has not designated any of its derivative contracts as cash flow hedges and has therefore not included its derivative contracts in estimating future cash flows. The future cash outflows associated with future development or abandonment of wells are included in the computation of the discounted present value of future net revenues for purposes of the ceiling limitation calculation. See Note 7 for further discussion of the full cost ceiling limitation.
Sales and abandonments of oil and natural gas properties being amortized are accounted for as adjustments to the full cost pool, with no gain or loss recognized, unless the adjustments would significantly alter the relationship between capitalized costs and proved oil and natural gas reserves. A significant alteration would not ordinarily be expected to occur upon the sale of reserves involving less than 25% of the proved reserve quantities of the cost center.
Property, Plant and Equipment, Net. Other capitalized costs, including drilling equipment, natural gas gathering and treating equipment, transportation equipment and other property and equipment are carried at cost. Renewals and improvements are capitalized while repairs and maintenance are expensed. Depreciation of such property and

equipment is computed using the straight-line method over the estimated useful lives of the assets, which range from 10 to 39 years for buildings and 3 to 30 years for equipment. When property and equipment components are disposed of, the cost and the related accumulated depreciation are removed and any resulting gain or loss is reflected in the consolidated statement of operations.

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Realization of the carrying value of property and equipment is reviewed for possible impairment whenever events or changes in circumstances indicate that the carrying value of such asset may not be recoverable. Assets are considered to be impaired if a forecast of undiscounted estimated future net operating cash flows directly related to the asset or asset group including disposal value, if any, is less than the carrying amount of the asset or asset group. If any asset or asset group is considered to be impaired, the impairment loss is measured as the amount by which the carrying amount of the asset or asset group exceeds its fair value. See Note 8 for further discussion of impairments.
Capitalized Interest. Interest is capitalized on assets being made ready for use using a weighted average interest rate based on the Company’s outstanding borrowings. During 2012, 2011 and 2010, interest of approximately $10.1 million, $1.0 million and $0.3 million, respectively, was capitalized on unproved properties that were not currently being depreciated or depleted and on which exploration activities were in progress. Additionally, $4.7 million, $2.0 million and $1.0 million were capitalized in 2012, 2011 and 2010, respectively, on midstream and corporate assets which were under construction.
Restricted Deposits. Restricted deposits represent bank trust and escrow accounts required by the Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement, surety bond underwriters, purchase agreements or other settlement agreements to satisfy the Company’s eventual responsibility to plug and abandon wells and remove structures when certain offshore fields are no longer in use. During 2010, $5.1 million was liquidated from the escrow accounts upon compliance with certain plugging and abandonment obligations. At December 31, 2012 and 2011, the Company had $27.9 million of such restricted deposits included as a long-term asset in the accompanying consolidated balance sheets.
Restricted deposits may also include escrow deposits received on pending sales of oil and natural gas properties. Amounts are considered restricted until the transaction closes. In December 2012, the Company entered into an agreement to sell certain of its oil and natural gas properties in the Permian Basin and received a $255.0 million deposit. At December 31, 2012, this deposit was included in current assets and current liabilities in the accompanying consolidated balance sheets. See Note 22 for further discussion of the sale of the oil and natural gas properties in the Permian Basin.
Goodwill. Goodwill represents the excess of the consideration paid over the fair value of identifiable net assets acquired as part of the acquisition of Arena Resources, Inc. (“Arena”). See Note 3 for discussion of this acquisition. Goodwill was assigned to the Company’s exploration and production segment and is not deductible for income tax purposes.
Goodwill is not amortized, but rather tested annually for impairment. The Company performs its annual goodwill impairment test as of July 1st and between annual evaluations if events occur or circumstances exist that would more-likely-than-not reduce the fair value of the reporting unit below its carrying amount. Such circumstances could include, but are not limited to (1) a significant or sustained decrease in oil and natural gas prices, (2) a significant adverse change in the economic or business climate, (3) an adverse action or assessment by a regulator and (4) the likelihood that a reporting unit or a significant portion of a reporting unit will be sold or otherwise disposed. When a portion of a reporting unit that constitutes a business is disposed, goodwill is allocated to that business based on the relationship of the fair value of the portion sold to the total reporting unit’s fair value.
When evaluating whether goodwill is impaired, the Company may elect to perform a qualitative assessment to determine whether it is necessary to perform the current two-step annual impairment test. If the Company determines, on the basis of qualitative factors, that the fair value of the reporting unit more-likely-than-not exceeds the carrying amount, the two-step impairment test is not required. However, if the Company determines it is necessary or elects to perform the two-step impairment test, the Company compares the fair value of the reporting unit to which the goodwill is assigned to the reporting unit’s carrying amount, including goodwill. The fair value of the reporting unit is estimated using the income, or discounted cash flow, approach. If the carrying amount of the reporting unit exceeds its fair value, then the amount of the impairment loss must be measured. The impairment loss would be calculated by comparing the implied fair value of reporting unit goodwill to the carrying amount of goodwill. In calculating the implied fair value of reporting unit goodwill, the fair value of the reporting unit is allocated to all of its other assets and liabilities based on their fair values. The excess of the fair value of a reporting unit over the amount assigned to its other assets and liabilities is the implied fair value of goodwill. An impairment loss would be recognized when the

carrying amount of goodwill exceeds its implied fair value.
Entry by the Company in December 2012 into an agreement to sell the Permian Properties was determined to be a triggering event. As such, an impairment test was performed as of December 31, 2012. See Note 9 for further discussion of goodwill and the impairment test performed.
Investments. Investments in marketable equity securities have been designated as available for sale and measured at fair value pursuant to the fair value option which requires unrealized gains and losses be reported in earnings.

Debt Issuance Costs. The Company amortizes debt issuance costs related to its long-term debt as interest expense over the scheduled maturity period of the related debt. The Company includes unamortized debt issuance costs in other assets in the consolidated balance sheet.

Asset Retirement Obligations. The Company owns oil and natural gas properties that require expenditures to plug, abandon and remediate wells at the end of their productive lives, in accordance with applicable federal and state laws. Liabilities for these asset retirement obligations are recorded in the period in which the liability is incurred (at the time the wells are drilled or acquired) at the estimated present value at the asset's inception, with the offsetting increase to property cost. These property costs are depreciated on a unit-of-production basis within the full cost pool. The liability accretes each period until the liability is settled or the well is sold, at which time the liability is removed. Both the accretion and the depreciation are included in the consolidated statement of operations. The Company determines its asset retirement obligations by calculating the present value of estimated expenses related to the liability. Estimating the future asset retirement obligations requires management to make estimates and judgments regarding timing, existence of a liability and what constitutes adequate restoration. Inherent in the present value calculation rates are the timing of settlement and changes in the legal, regulatory, environmental and political environments, which are subject to change. See Note 15 for further discussion of the Company's asset retirement obligations.

In certain instances, the Company is required to make deposits to escrow accounts for future plugging and abandonment obligations. See Restricted Deposits discussed above.

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

The Company accounts for natural gas production imbalances using the sales method, whereby it recognizes revenue on all natural gas sold to its customers notwithstanding the fact that its ownership may be less than 100% of the natural gas sold. Liabilities are recorded for imbalances greater than the Company's proportionate share of remaining estimated natural gas reserves. The Company has recorded a liability for natural gas imbalance positions related to natural gas properties with insufficient proved reserves of $3.6 million and $1.7 million at December 31, 2012 and 2011, respectively. The Company includes the gas imbalance positions in other long-term obligations in the consolidated balance sheet.

The Company accounts for its two construction contracts, discussed in Note 12, using the completed-contract method, under which contract revenues and costs are recognized when work under the contract is completed or substantially completed and assets have been transferred. In the interim, costs incurred on and billings related to contracts in process are accumulated on the balance sheet. Contract gains or losses are recorded as development costs within the Company's oil and natural gas properties as part of the full cost pool. Contract losses are recorded at the time it is determined that a loss will be incurred. Contract gains, if any, are recorded at the end of the project.

The Company recognizes revenues and expenses generated from daywork and footage drilling contracts as the services are performed as the Company does not bear the risk of completion of the well. The Company may receive lump-sum fees for the mobilization of equipment and personnel. Mobilization fees received and costs incurred to mobilize a rig from one market to another are recognized over the term of the related drilling contract. The contract terms can range from one month to two years.

Midstream services revenues are recognized upon delivery of natural gas to customers and/or when services are rendered, pricing is determined and collectability is reasonably assured. Revenues from third-party midstream services are presented on a gross basis, as the Company acts as a principal by taking ownership of the natural gas purchased and taking responsibility of fulfillment for natural gas volumes sold. Revenue from sales of CO_2 is recognized when the product is delivered to the customer.

Stock-Based Compensation. The Company grants restricted stock awards to members of its Board of Directors and its employees. Such awards and the related stock-based compensation cost are measured based on the calculated fair value of the award on the grant date. The expense is recognized on a straight-line basis over the employee's requisite service period, generally the vesting period of the award. To the extent stock-based compensation cost relates to employees directly involved in oil and natural gas exploration and development activities, such amounts are

capitalized to oil and natural gas properties. Amounts not capitalized are recognized as general and administrative expense, production expense, midstream and marketing expense and drilling and services expense in the consolidated statement of operations. The related excess tax benefit received upon vesting of restricted stock, if any, is reflected in the consolidated statement of cash flows as a financing activity. The related excess tax expense due upon vesting of restricted stock, if any, is reflected in the consolidated statement of cash flows as an operating activity.
Advertising Costs. The Company expenses advertising costs as incurred. Advertising and promotional costs were $11.8 million, $4.8 million, and $5.4 million, respectively, during the years ended December 31, 2012, 2011 and 2010.

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Income Taxes. Deferred income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their reported amounts in the financial statements. Deferred tax assets are reduced by a valuation allowance as necessary when a determination is made that it is more likely than not that some or all of the deferred assets will not be realized based on all available evidence.

The Company has elected an accounting policy in which interest and penalties on income taxes are presented as a component of the income tax provision, rather than as a component of interest expense. Interest and penalties resulting from the underpayment or the late payment of income taxes due to a taxing authority and interest and penalties accrued relating to income tax contingencies, if any, are presented, on a net of tax basis, as a component of the income tax provision.

Variable Interest Entities. An entity is referred to as a VIE if it possesses one of the following criteria: (i) it is thinly capitalized, (ii) the residual equity holders do not control the entity, (iii) the equity holders are shielded from the economic losses, (iv) the equity holders do not participate fully in the entity's residual economics, or (v) the entity was established with non-substantive voting interests. The Company consolidates a VIE when it has determined it is the primary beneficiary, which requires significant judgment. The primary beneficiary of a VIE has both the power to direct the activities that most significantly impact the activities of the VIE and the right to receive benefits or the obligation to absorb losses of the entity that could be potentially significant to the VIE. In addition to the VIEs that the Company consolidates, the Company also holds a variable interest in another VIE that is not consolidated as it was determined that the Company is not the primary beneficiary. The Company continually monitors both consolidated and unconsolidated VIEs to determine if any events have occurred that could cause the primary beneficiary to change.

Noncontrolling Interest. Noncontrolling interest represents third-party ownership interests in the Company's subsidiaries and consolidated VIEs and is included as a component of equity in the consolidated balance sheet and consolidated statement of changes in equity. The Company's subsidiary Cholla Pipeline, L.P. had a 1.29% noncontrolling interest for the years ended December 31, 2012, 2011 and 2010. Other noncontrolling interest is third-party ownership in the Company's VIEs. See Note 4 for discussion of the Company's VIEs.

Earnings per Share. Basic earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by dividing earnings available to common stockholders by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculation consist of unvested restricted stock awards, using the treasury method, and convertible preferred stock. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. See Note 20 for additional information on the Company's earnings per share calculation.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Environmental expenditures are expensed or capitalized, as appropriate, depending on future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and costs can be reasonably estimated. See Note 16 for discussion of the Company's commitments and contingencies.

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

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A default by the Company under its senior credit facility constitutes a default under its derivative contracts with counterparties that are lenders under the senior credit facility. The Company does not require collateral or other security from counterparties to support derivative instruments. The Company has master netting agreements with all of its derivative counterparties, which allow the Company to net its derivative assets and liabilities with the same counterparty. As a result of the netting provisions, the Company's maximum amount of loss under derivative transactions due to credit risk is limited to the net amounts due from the counterparties under the derivative contracts. The Company's loss is further limited as any amounts due from a defaulting counterparty that is a lender under the senior credit facility can be offset against amounts owed to such counterparty under the Company's senior credit facility. As of December 31, 2012, the counterparties to the Company's open derivative contracts consisted of 15 financial institutions, 13 of which are also lenders under the Company's senior credit facility. As a result, the Company is not required to post additional collateral under derivative contracts as the majority of the counterparties to the Company's derivative contracts share in the collateral supporting the Company's senior credit facility. To secure their obligations under the derivative contracts novated by the Company, the Permian Trust and Mississippian Trust II have each given the counterparties to such contracts a lien on its royalty interests. See Note 4 for additional information on the Permian Trust's and Mississippian Trust II's derivative contracts.

The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property, the Company makes full payment for costs associated with the property and seeks reimbursement from the other working interest owners in the property for their share of those costs. The Company's joint interest partners consist primarily of independent oil and gas producers. If the oil and gas exploration and production industry in general was adversely affected, the ability of the joint interest partners to reimburse the Company could be adversely affected.

The purchasers of the Company's oil and natural gas production consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. See Note 23 for information regarding the Company's major customers. The Company believes alternate purchasers are available in its areas of operations and does not believe the loss of any one purchaser would materially affect the Company's ability to sell the oil and natural gas it produces. Additionally, the Company has not experienced any significant losses from uncollectible accounts. See Note 6 for information regarding the Company's allowance for doubtful accounts.

Recently Adopted Accounting Pronouncements. In May 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS" ("ASU 2011-04"), which clarifies the FASB's intent regarding the application of existing fair value measurements and requires additional disclosure of information regarding valuation processes and inputs used. The new disclosure requirements, which are effective for interim and annual reporting periods beginning after December 15, 2011, were implemented by the Company in the first quarter of 2012. The implementation of ASU 2011-04 had no impact on the Company's financial position or results of operations. See Note 5 for the Company's fair value disclosures.

In September 2011, the FASB issued ASU 2011-08, which allows an entity the option of performing a qualitative assessment to determine whether it is necessary to perform the previously required two-step annual impairment test. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit more-likely-than-not exceeds the carrying amount, the two-step impairment test is not required. ASU 2011-08 does not change how goodwill is calculated or assigned to reporting units, nor does it revise the requirement to test goodwill annually for impairment or amend the requirement to test goodwill for impairment between annual tests if events or circumstances warrant. ASU 2011-08 is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The adoption of ASU 2011-08 did not impact the carrying value of the Company's goodwill. See Note 9 for discussion of goodwill and the Company's impairment assessments.

Recent Accounting Pronouncement Not Yet Adopted. In December 2011, the FASB issued Accounting Standards Update 2011-11, "Disclosures about Offsetting Assets and Liabilities" ("ASU 2011-11"), and in January 2013 issued Accounting Standards Update 2013-01, "Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities" ("ASU 2013-01"). These updates require disclosures about the nature of an entity's rights of offset and related arrangements associated with its recognized derivatives contracts. The guidance is effective for interim and annual periods beginning on or after January 1, 2013. As the additional requirements under ASU 2011-11 and ASU 2013-01, which will be implemented January 1, 2013, pertain to disclosures of offsetting assets and liabilities, no effect on the Company's financial position or results of operations is expected.

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2. Supplemental Cash Flow Information

Supplemental disclosures to the consolidated statements of cash flows are presented below:

	Years Ended December 31,		
	2012	2011	2010
	(In thousands)		
Supplemental Disclosure of Cash Flow Information			
Cash paid for interest, net of amounts capitalized	$ 257,152	$ 224,127	$ 210,112
Cash paid (received) for income taxes	1,324	2,083	(1,508)
Supplemental Disclosure of Noncash Investing and Financing Activities			
Deposit on pending sale	$ 255,000	$ —	$ —
Change in accrued capital expenditures	27,610	89,388	85,282
Adjustment to oil and natural gas properties for estimated contract loss	50,000	25,000	105,000
Asset retirement costs capitalized	7,479	5,716	17,347
Common stock issued in connection with acquisition	542,138	—	1,246,334
Stock issued to satisfy settlement	—	—	12,200

3. Acquisitions and Divestitures

2010 Acquisitions and Divestitures

Arena Acquisition. On July 16, 2010, the Company acquired 100% of the outstanding common stock of Arena (“Arena Acquisition”). At the time of the acquisition, Arena was engaged in oil and natural gas exploration, development and production, with activities in Oklahoma, Texas, New Mexico and Kansas. In connection with the acquisition, the Company issued 4.7771 shares of its common stock and paid $4.50 in cash to Arena stockholders for each outstanding share of Arena unrestricted common stock. This resulted in the issuance of approximately 190.3 million shares of Company common stock and payment of approximately $177.9 million in cash for an aggregate estimated purchase price to stockholders of Arena equal to approximately $1.4 billion. For purposes of purchase accounting, the value of the common stock issued was determined based on the closing price of $6.55 per share of the Company’s common stock on the New York Stock Exchange at July 16, 2010, the acquisition date. The Company incurred acquisition-related costs of approximately $0.6 million and $17.0 million for the years ended December 31, 2011 and 2010, respectively, which have been included in general and administrative expenses in the accompanying consolidated statements of operations.

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In the second quarter of 2011, the Company completed its valuation of assets acquired and liabilities assumed related to the Arena Acquisition, which are included in the following table (in thousands):

Current assets	$83,563
Oil and natural gas properties(1)	1,587,630
Other property, plant and equipment	5,963
Long-term deferred tax assets	48,997
Other long-term assets	16,181
Goodwill(2)	235,396
Total assets acquired	1,977,730
Current liabilities	38,964
Long-term deferred tax liability(2)	503,483
Other long-term liabilities	8,851
Total liabilities assumed	551,298
Net assets acquired	$1,426,432

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(1) Weighted average commodity prices utilized in the determination of the fair value of oil and natural gas properties were $105.58 per barrel of oil and $8.56 per Mcf of natural gas, after adjustment for transportation fees and regional price differentials. The prices utilized were based upon forward commodity strip prices, as of July 16, 2010, for the first four years and escalated for inflation at a rate of 2.5% annually beginning with the fifth year through the end of production, which was more than 50 years. These assumptions represent Level 3 inputs. Approximately 91.0% of the fair value allocated to oil and natural gas properties is attributed to oil reserves.

(2) The Company received carryover tax basis in Arena's assets and liabilities because the merger was not a taxable transaction under the Internal Revenue Code ("IRC"). Based upon the final purchase price allocation, a step-up in basis related to the property acquired from Arena resulted in a net deferred tax liability of approximately $454.5 million, which in turn contributed to an excess of the consideration transferred to acquire Arena over the estimated fair value on the acquisition date of the net assets acquired, or goodwill.

The following unaudited pro forma results of operations are provided for the year ended December 31, 2010 as though the Arena Acquisition had been completed as of the beginning of that year. The pro forma combined results of operations for the year ended December 31, 2010 was prepared by adjusting the historical results of the Company to include the historical results of Arena, certain reclassifications to conform Arena's presentation to the Company's accounting policies and the impact of the purchase price allocation. These supplemental pro forma results of operations are provided for illustrative purposes only and do not purport to be indicative of the actual results that would have been achieved by the combined company for the period presented or that may be achieved by the combined company in the future. The pro forma results of operations do not include any cost savings or other synergies that resulted from the acquisition or any estimated costs that have been incurred by the Company to integrate Arena. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Year Ended December 31, 2010 (In thousands, except per share data) (Unaudited)
Revenues	$1,046,569
Income available to SandRidge Energy, Inc. common stockholders(1)	$171,654
Earnings per common share	
Basic	$0.44

Diluted	$0.43

(1) Includes a $454.5 million reduction in tax expense related to the release of a portion of the Company's valuation allowance on existing deferred tax assets.

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Revenues of $112.1 million and earnings of $90.1 million generated by the oil and natural gas properties acquired in the Arena Acquisition for the period of July 17, 2010 through December 31, 2010 have been included in the Company's accompanying consolidated statements of operations for the year ended December 31, 2010.

Divestitures. The Company completed the following divestitures in 2010, both of which were accounted for as adjustments to the full cost pool with no gain or loss recognized:

- On August 26, 2010, the Company sold certain deep acreage rights in the Cana Shale play in western Oklahoma for estimated net proceeds of $109.4 million, net of post-closing adjustments. The Company retained the shallow rights associated with this acreage.
- On December 10, 2010, the Company sold approximately 40,000 net acres in the Avalon Shale and Bone Spring reservoirs of the Permian Basin for $102.1 million, net of post-closing adjustments. There was no production or proved reserves associated with these assets and the Company retained all rights above and below the Avalon Shale and Bone Spring formations.

2011 Divestitures

The Company completed the following divestitures in 2011, all of which were accounted for as adjustments to the full cost pool with no gain or loss recognized:

- In July 2011, the Company sold its Wolfberry assets in the Permian Basin for $151.6 million, net of fees and post-closing adjustments.
- In August 2011, the Company sold certain oil and natural gas properties in Lea County and Eddy County, New Mexico, for $199.0 million, net of fees and post-closing adjustments.
- In November 2011, the Company sold its east Texas natural gas properties in Gregg, Harrison, Rusk and Panola counties for $225.4 million, net of fees and post-closing adjustments.

2012 Acquisitions and Divestitures

Dynamic Acquisition. The Company acquired 100% of the equity interests of Dynamic on April 17, 2012 for total consideration of 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.

A preliminary allocation of the purchase price as of April 17, 2012 was prepared in connection with the Company's June 30, 2012 consolidated financial statements. Upon completion of the initial purchase price allocation, the Company reviewed its assessment, including the identification and valuation of assets acquired and liabilities assumed. Upon verification of the purchase price allocation, the Company recorded a bargain purchase gain for the difference between the purchase price and the estimated fair value of the net assets acquired. During the fourth quarter of 2012, the Company updated certain of the estimates used in the preliminary purchase price allocation, primarily with respect to deferred taxes and other accruals for which the Company was awaiting additional information, resulting in adjustments of $1.8 million to the bargain purchase gain and $3.0 million to the initial valuation allowance release, which resulted in income tax expense. The Company recorded a net deferred tax liability associated with the Dynamic Acquisition, which resulted in the release of a portion of the previously recorded valuation allowance on the Company's net deferred tax asset. The Company will monitor the need to further adjust the Company's valuation allowance on its net deferred tax asset as the purchase price allocation is finalized and the full impact of the acquisition is determined, both of which are expected to occur by the second quarter of 2013. The Company believes the estimates used in the purchase price allocation are reasonable and the significant effects of the Dynamic Acquisition are properly reflected. However, the estimates are subject to change as additional information becomes available and is assessed by the Company. Changes to the purchase price allocation and any corresponding change to the bargain purchase gain will be adjusted retrospectively to the date of the acquisition.

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The following table summarizes the estimated values of assets acquired and liabilities assumed in connection with the Dynamic Acquisition (in thousands, except stock price):

Consideration(1)	
Shares of SandRidge common stock issued	73,962
SandRidge common stock price	$7.33
Fair value of common stock issued	542,138
Cash consideration(2)	680,000
Cash balance adjustment(3)	13,091
Total purchase price	$1,235,229
Estimated Fair Value of Liabilities Assumed	
Current liabilities	$129,363
Asset retirement obligation(4)	315,922
Long-term deferred tax liability(5)	100,288
Other non-current liabilities	4,469
Amount attributable to liabilities assumed	550,042
Total purchase price plus liabilities assumed	1,785,271
Estimated Fair Value of Assets Acquired	
Current assets	142,027
Oil and natural gas properties(6)	1,746,753
Other property, plant and equipment	1,296
Other non-current assets	17,891
Amount attributable to assets acquired	1,907,967
Bargain purchase gain(7)	$(122,696)

(1) Consideration paid by the Company consisted of 74 million shares of SandRidge common stock and cash of approximately $680.0 million. The value of the stock consideration is based upon the closing price of $7.33 per share of SandRidge common stock on April 17, 2012, which was the closing date of the Dynamic Acquisition. Under the acquisition method of accounting, the purchase price is determined based on the total cash paid and the fair value of SandRidge common stock issued on the acquisition date.

(2) Cash consideration paid, including amounts paid to retire Dynamic's long-term debt, was funded through a portion of the net proceeds from the Company's issuance of $750.0 million of unsecured 8.125% Senior Notes due 2022.

(3) In accordance with the acquisition agreement, the Company remitted to the seller a cash payment equal to Dynamic's average daily cash balance for the 30-day period ending on the second day prior to closing. This resulted in an additional cash payment by SandRidge of $13.1 million at closing.

(4) The estimated fair value of the acquired asset retirement obligation was determined using the Company's credit adjusted risk-free rate.

(5) The net deferred tax liability is primarily a result of the difference between the estimated fair value and the Company's expected tax basis in the assets acquired and liabilities assumed. The net deferred tax liability also includes the effects of deferred tax assets associated with net operating losses and other tax attributes acquired as a result of the Dynamic Acquisition.

(6) The fair value of oil and natural gas properties acquired was estimated using a discounted cash flow model, with future cash flows estimated based upon projections of oil and natural gas reserve quantities and weighted average oil and natural gas prices of $113.62 per barrel of oil and $3.83 per Mcf of natural gas, after adjustment for transportation fees and regional price differentials. The commodity prices utilized were based upon commodity strip prices as of April 17, 2012 for the first four years and escalated for inflation at a rate of 2.0% annually beginning with the fifth year through the end of production. Future cash flows were discounted using an industry weighted average cost of capital rate.

(7) The bargain purchase gain results from the excess of the fair value of net assets acquired over consideration paid and, as additional information becomes available, is subject to adjustment. To validate the estimated bargain purchase gain on this acquisition, the Company reviewed its initial identification and valuation of assets acquired and liabilities assumed. The Company believes it was able to acquire Dynamic for less than the estimated fair value of its net assets due to their offshore location resulting in less bidding competition.

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The market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk-adjusted discount rates used by the Company to estimate the fair market value of the oil and natural gas properties acquired represent Level 3 inputs.

The following unaudited pro forma combined results of operations for the years ended December 31, 2012 and 2011 are presented as though the Dynamic Acquisition had been completed as of January 1, 2011. The pro forma combined results of operations for the years ended December 31, 2012 and 2011 have been prepared by adjusting the historical results of the Company to include the historical results of Dynamic, certain reclassifications to conform Dynamic's presentation and accounting policies to the Company's and the impact of the bargain purchase gain resulting from the preliminary purchase price allocation. These supplemental pro forma results of operations are provided for illustrative purposes only and do not purport to be indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. The pro forma results of operations do not include any cost savings or other synergies that may result, from the Dynamic Acquisition or any estimated costs that will be incurred to integrate Dynamic. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Year Ended December 31,	
	2012(1)	2011(2)
	(in thousands, except per share data)	
	(Unaudited)	
Revenues	$2,908,899	$1,932,945
Net income	$39,563	$509,644
(Loss applicable) income available to SandRidge Energy, Inc. common stockholders	$(120,962)	$399,278
(Loss) earnings per common share		
Basic	$(0.25)	$0.84
Diluted	$(0.25)	$0.80

(1) Pro forma net income, income available to SandRidge Energy, Inc. common stockholders and earnings per common share exclude a $122.7 million bargain purchase gain, a $100.3 million partial valuation allowance release included in income tax benefit, $10.9 million of fees incurred to secure financing for the Dynamic Acquisition included in interest expense and $13.0 million of transaction costs incurred and included in general and administrative expense in the accompanying consolidated statements of operations for the year ended December 31, 2012.

(2) Pro forma net income, income applicable to SandRidge Energy, Inc. common stockholders and earnings per common share include a $122.7 million bargain purchase gain, a $100.3 million partial valuation allowance release, $10.9 million of fees incurred to secure financing for the Dynamic Acquisition and $13.0 million of estimated transaction costs.

Revenues of $365.0 million and income from operations of $81.5 million associated with Dynamic have been included in the accompanying consolidated statements of operations for the year ended December 31, 2012. Additionally, the Company has incurred $13.0 million in acquisition-related costs for the Dynamic Acquisition, which have been included in general and administrative expense in the accompanying consolidated statements of operations for the year ended December 31, 2012.

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 approximately $130.8 million, net of post-closing adjustments. The sale of the acreage and working interests in wells was accounted for as an adjustment to the full cost pool with no gain or loss recognized.

Acquisition of Gulf of Mexico Properties. In June 2012, the Company acquired oil and natural gas properties in the Gulf of Mexico (the “Gulf of Mexico Properties”) 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. This 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.

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This acquisition qualified as a business combination for accounting purposes and, as such, the Company estimated the fair value of the acquired properties as of the June 20, 2012 acquisition date, which was the date on which the Company obtained control of the properties. The fair value was estimated using a discounted cash flow model based upon market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk-adjusted discount rates. These assumptions represent Level 3 inputs.

The Company estimated the consideration paid for these properties approximated the fair value that would be paid by a typical market participant. As a result, no goodwill or bargain purchase gain was recognized in conjunction with the purchase. Acquisition-related costs of $0.2 million have been expensed as incurred in general and administrative expense in the accompanying consolidated statements of operations for the year ended December 31, 2012. Revenues of $26.2 million and earnings of $19.1 million generated by the acquired properties have been included in the accompanying consolidated statements of operations for the year ended December 31, 2012.

The following table summarizes the consideration paid to acquire the properties and the amounts of the assets acquired and liabilities assumed as of June 20, 2012. The purchase price allocation is preliminary and subject to adjustment upon the final closing settlement to be completed during the first quarter of 2013 (in thousands):

Consideration paid	
Cash, net of purchase price adjustments	$38,458
Fair value of identifiable assets acquired and liabilities assumed	
Proved developed and undeveloped properties	$93,901
Asset retirement obligations	(55,443)
Total identifiable net assets	$38,458

The following unaudited pro forma combined results of operations for the years ended December 31, 2012 and 2011 are presented as though the Company acquired the Gulf of Mexico Properties as of January 1, 2011. The pro forma combined results of operations for the years ended December 31, 2012 and 2011 have been prepared by adjusting the historical results of the Company to include the historical results of the acquired properties and estimates of the effect of the transaction on the combined results. These supplemental pro forma results of operations are provided for illustrative purposes only and do not purport to be indicative of the actual results that would have been achieved had the transaction been in effect for the periods presented or that may be achieved by the Company in the future. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Year Ended December 31,	
	2012	2011
	(In thousands, except per share data)	
	(Unaudited)	
Revenues	$ 2,759,381	$ 1,502,325
Net income	$ 248,920	$ 191,335
Income available to SandRidge Energy, Inc. common stockholders	$ 88,395	$ 81,429
Earnings per common share		
Basic	$ 0.19	$ 0.20
Diluted	$ 0.19	$ 0.20

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 Permian Trust's area of mutual interest (the "Permian Properties") for $2.6 billion, subject to post-closing adjustments. In December 2012, the Company received a $255.0 million escrow deposit associated with the sale of the Permian Properties. This deposit is included as a restricted deposit in the accompanying consolidated balance sheets at December 31, 2012. This deposit was released from escrow to the Company on February 26, 2013 in connection with closing of the sale of the Permian Properties. See Note 22 for further discussion of the Permian Properties sale.

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Sale of Working Interests and Associated Drilling Carry Commitments

During 2011 and the first quarter of 2012, the Company completed two transactions whereby it sold non-operated working interests in the Mississippian formation. Each of these transactions is described in more detail below. In these transactions, the Company received aggregate cash proceeds of $500.0 million for the sale of working interests and received drilling carry commitments to fund a portion of its future drilling and completion costs totaling $1.0 billion. For accounting purposes, initial cash proceeds from these transactions were reflected as a reduction of oil and natural gas properties with no gain or loss recognized, and amounts received or billed during 2011 and 2012 attributable to the drilling carry reduced the Company's capital expenditures. These transactions and the associated drilling carries as of December 31, 2012, are as follows:

Partner	Closing Date	Proceeds Received At Closing(1)	Drilling Carry Recorded	Drilling Carry Remaining
		(In millions)		
Atinum MidCon I, LLC	September 2011	$287.0	$ 157.2	$92.8
Repsol E&P USA, Inc.	January 2012	272.5	229.3	520.7
		$559.5	$ 386.5	$613.5

(1) Includes amounts related to the drilling carry.

In September 2011, the Company sold to Atinum MidCon I, LLC ("Atinum") non-operated working interests equal to approximately 113,000 net acres in the Mississippian formation in northern Oklahoma and southern Kansas for approximately $250.0 million. In addition, Atinum agreed to pay the development costs related to its working interest, as well as a portion of the Company's development costs equal to Atinum's working interest for wells within an area of mutual interest up to $250.0 million. The Company expects Atinum's funding of the Company's development cost for wells within the area of mutual interest to occur over a period not to exceed three years.

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 interests, as well as a portion of the Company's development costs equal to 200% of Repsol's working interests 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.

During the years ended December 31, 2012 and 2011, the Company recorded approximately $367.6 million and $18.9 million, respectively, for Atinum's and Repsol's drilling carries, which reduced the Company's capital expenditures for the respective period.

4. Variable Interest Entities

The Company consolidates the activities of VIEs of which it is the primary beneficiary. The primary beneficiary of a VIE is that variable interest holder possessing a controlling financial interest through (i) its power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (ii) its obligation to absorb losses or its right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether the Company owns a variable interest in a VIE, the Company performs a qualitative analysis of the entity's design, organizational structure, primary decision makers and related financial agreements.

The Company’s significant associated VIEs, including those for which the Company has determined it is the primary beneficiary and those for which it has determined it is not, are described below.

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Grey Ranch Plant, L.P ("GRLP"). Primarily engaged in treating and transportation of natural gas, GRLP is a limited partnership that operates the Company's Grey Ranch plant (the "Plant") located in Pecos County, Texas. The Company has long-term operating and gathering agreements with GRLP and also owns a 50% interest in GRLP, which represent a variable interest. Income or losses of GRLP are allocated to the partners based on ownership percentage and any operating or cash shortfalls require contributions from the partners. The Company has determined that GRLP qualifies as a VIE because certain equity holders lack the ability to participate in decisions impacting GRLP. Agreements related to the ownership and operation of GRLP provide for GRLP to pay management fees to the Company to operate the Plant and lease payments for the Plant. Under the operating agreements, lease payments are reduced if throughput volumes are below those expected. The Company has determined that it is the primary beneficiary of GRLP as it has both (i) the power to direct the activities of GRLP that most significantly impact its economic performance as operator of the Plant and (ii) the obligation to absorb losses, as a result of the operating and gathering agreements, that could potentially be significant to GRLP and, therefore, consolidates the activity of GRLP in its consolidated financial statements. The 50% ownership interest not held by the Company is presented as noncontrolling interest in the consolidated financial statements.

GRLP's assets can only be used to settle its own obligations and not other obligations of the Company. GRLP's creditors have no recourse to the general credit of the Company. Although GRLP is included in the Company's consolidated financial statements, the Company's legal interest in GRLP's assets is limited to its 50% ownership. At December 31, 2012 and 2011, $1.1 million and $8.2 million, respectively, of noncontrolling interest in the accompanying consolidated balance sheets were related to GRLP. GRLP's assets and liabilities, after considering the effects of intercompany eliminations, included in the accompanying consolidated balance sheets at December 31, 2012 and 2011 consisted of the following (in thousands):

	December 31,	
	2012	2011
Cash and cash equivalents	$1,080	$1,702
Accounts receivable, net	20	24
Inventory	109	109
Prepaid expenses	64	176
Total current assets	1,273	2,011
Other property, plant and equipment, net	1,246	14,985
Total assets	$2,519	$16,996
Accounts payable and accrued expenses	$274	$280
Total liabilities	$274	$280

Grey Ranch Plant Genpar, LLC ("Genpar"). The Company owns a 50% interest in Genpar, the managing partner and 1% owner of GRLP. Additionally, the Company serves as Genpar's administrative manager. Genpar's ownership interest in GRLP is its only asset. As managing partner of GRLP, Genpar has the sole right to manage, control and conduct the business of GRLP. However, Genpar is restricted from making certain major decisions, including the decision to remove the Company as operator of the Plant. The rights afforded the Company under the Plant operating agreement and the restrictions on Genpar limit Genpar's ability to make decisions on behalf of GRLP. Therefore, Genpar is considered a VIE. Although both the Company and Genpar's other equity owner share equally in Genpar's economic losses and benefits and also have agreements that may be considered variable interests, the Company determined it was the primary beneficiary of Genpar due to (i) its ability, as administrative manager and operator of the Plant, to direct the activities of Genpar that most significantly impact its economic performance and (ii) its obligation or right, as operator of the Plant, to absorb the losses of or receive benefits from Genpar that could potentially be significant to Genpar. As the primary beneficiary, the Company consolidates Genpar's activity. However, its sole asset, the investment in GRLP, is eliminated in consolidation. Genpar has no liabilities.

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Royalty Trusts. SandRidge owns beneficial interests in three Delaware statutory trusts. The Mississippian Trust I, Permian Trust and Mississippian Trust II (each individually, a "Royalty Trust" and collectively, the "Royalty Trusts") completed initial public offerings of their common units in April 2011, August 2011 and April 2012, respectively. Concurrent with the closing of each offering, the Company conveyed certain royalty interests to each Royalty Trust in exchange for the net proceeds of the offering and units representing beneficial interests in the Royalty Trust. Royalty interests conveyed to the Royalty Trusts are in certain existing wells and wells to be drilled on oil and natural gas properties leased by the Company in defined areas of mutual interest. Conveyance of the royalty interests was recorded at the Company's historical cost. The following table summarizes information about each Royalty Trust upon completion of its initial public offering:

	Mississippian Trust I	Permian Trust	Mississippian Trust II
Net proceeds of offering (in millions)	$336.9	$580.6	$587.1
Total outstanding common units	21,000,000	39,375,000	37,293,750
Total outstanding subordinated units	7,000,000	13,125,000	12,431,250
Beneficial interest owned by Company(1)	38.4 %	34.3 %	39.9 %
Liquidation date(2)	12/31/2030	3/31/2031	12/31/2031

(1) During the year ended December 31, 2012, the Company sold common units of the Mississippian Trust I and the Permian Trust it owned in transactions exempt from registration under Rule 144 under the Securities Act. These transactions decreased the Company's beneficial interests in the Royalty Trusts. See further discussion of the unit sales below.

(2) At the time each Royalty Trust terminates, 50% of the royalty interests conveyed to the Royalty Trust will automatically revert back to the Company, and the remaining 50% will be sold with the proceeds distributed to Royalty Trust unitholders.

The Royalty Trusts make quarterly cash distributions to unitholders based on calculated distributable income. In order to provide support for cash distributions on the common units, the Company agreed to subordinate a portion of the units it owns in each Royalty Trust (the "subordinated units"), which constitute 25% of the total outstanding units of each Royalty Trust. The subordinated units are entitled to receive pro rata distributions from the Royalty Trusts each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is no less than the applicable quarterly subordination threshold. If there is not sufficient cash to fund such a distribution on all common units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on all common units, including common units held by the Company. In exchange for agreeing to subordinate a portion of its Royalty Trust units, SandRidge is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Royalty Trust units exceeds the applicable quarterly incentive threshold. The Royalty Trusts declared and paid quarterly distributions during the years ended December 31, 2012 and 2011 as follows (in millions):

	Year Ended December 31,	
	2012	2011
Total distributions	$275.0	$91.2
Distributions to third-party unitholders	$181.7	$57.4

Pursuant to the trust agreements governing the Royalty Trusts, SandRidge has a loan commitment to each Royalty Trust, whereby SandRidge will loan funds to the Royalty Trust on an unsecured basis, with terms substantially the same as would be obtained in an arm's length transaction between SandRidge and an unaffiliated party, if at any time the Royalty Trust's cash is not sufficient to pay ordinary course administrative expenses as they become due. Any funds loaned may not be used to satisfy indebtedness of the Royalty Trust or to make distributions. There were no amounts outstanding under the loan commitments at December 31, 2012 or 2011.

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The Company and one of its wholly owned subsidiaries entered into a development agreement with each Royalty Trust that obligates the Company to drill, or cause to be drilled, a specified number of wells within respective areas of mutual interest, which are also subject to the royalty interests granted to the Mississippian Trust I, Permian Trust and Mississippian Trust II, by December 31, 2015, March 31, 2016 and December 31, 2016, respectively. At the end of the fourth full calendar quarter following satisfaction of the Company's drilling obligation (the "subordination period"), the subordinated units of each Royalty Trust will automatically convert into common units on a one-for-one basis and the Company's right to receive incentive distributions will terminate. One of the Company's wholly-owned subsidiaries also granted to each Royalty Trust a lien on the Company's interests in the properties where the development wells will be drilled in order to secure the estimated amount of drilling costs for the Royalty Trust's interests in the wells. As the Company fulfills its drilling obligation to each Royalty Trust, development wells that have been drilled and perforated for completion are released from the lien (subject to completion of an initial minimum number of wells for the Mississippian Trust II) and the total amount that may be recovered by each Royalty Trust is proportionately reduced. As of December 31, 2012, the total maximum amount recoverable by the Royalty Trusts under the liens was approximately $423.4 million.

Additionally, the Company and each Royalty Trust entered into an administrative services agreement, pursuant to which the Company provides certain administrative services to the Royalty Trust, including hedge management services to the Permian Trust and Mississippian Trust II. The Company also entered into derivatives agreements with each Royalty Trust, pursuant to which the Company provides to the Royalty Trust the economic effects of certain of the Company's derivative contracts. Substantially concurrent with the execution of the derivatives agreements with the Permian Trust and Mississippian Trust II, the Company novated certain of the derivative contracts underlying the respective derivatives agreements to the Permian Trust and Mississippian Trust II. In April 2012, the Company novated certain additional derivative contracts underlying the derivatives agreement to the Permian Trust. The tables below present the open oil and natural gas commodity derivative contracts at December 31, 2012 underlying the derivatives agreements, including the contracts novated to the Permian Trust and Mississippian Trust II. The combined volume in the tables below reflects the total volume of the Royalty Trusts' open oil and natural gas commodity derivative contracts. See Note 14 for further discussion of the derivatives agreement between the Company and each Royalty Trust.

Oil Price Swaps Underlying the Royalty Trust Derivatives Agreements

	Notional (MBbls)	Weighted Average Fixed Price
January 2013 — December 2013	1,814	$103.03
January 2014 — December 2014	2,053	$100.78
January 2015 — December 2015	667	$101.02

Natural Gas Collars Underlying the Royalty Trust Derivatives Agreements

	Notional (MMcf)	Collar Range
January 2013 — December 2013	858	$4.00 — $7.15
January 2014 — December 2014	937	$4.00 — $7.78
January 2015 — December 2015	1,010	$4.00 — $8.55

Oil Price Swaps Underlying the Derivatives Agreements and Novated to the Royalty Trusts

	Notional (MBbls)	Weighted Average Fixed Price
January 2013 — December 2013	1,021	$103.35
January 2014 — December 2014	799	$100.59
January 2015 — March 2015	104	$100.90

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The Royalty Trusts are considered VIEs due to the lack of voting or similar decision-making rights of the Royalty Trusts' equity holders regarding activities that have a significant effect on the economic success of the Royalty Trusts. The Company has determined it is the primary beneficiary of the Royalty Trusts as it has (a) the power to direct the activities that most significantly impact the economic performance of the Royalty Trusts through (i) its participation in the creation and structure of the Royalty Trusts, (ii) the manner in which it fulfills its drilling obligations to the Royalty Trusts and (iii) its operation of a majority of the oil and natural gas properties that are subject to the conveyed royalty interests and marketing of the associated production, and (b) the obligation to absorb losses and right to receive residual returns, through its variable interests in the Royalty Trusts, including ownership of common and subordinated units and residual interest in the royalty interests at termination, that could potentially be significant to the Royalty Trusts. As a result, the Company began consolidating the activities of the Royalty Trusts into its results of operations upon conveyance of the royalty interests to each Royalty Trust. The common units of the Royalty Trusts owned by third parties are reflected as noncontrolling interest in the consolidated financial statements.

Each Royalty Trust's assets can be used to settle only that Royalty Trust's obligations and not other obligations of the Company or another Royalty Trust. The Royalty Trusts' creditors have no contractual recourse to the general credit of the Company. Although the Royalty Trusts are included in the Company's consolidated financial statements, the Company's legal interest in the Royalty Trusts' assets is limited to its ownership of the Royalty Trusts units. At December 31, 2012 and 2011, $1.5 billion and $914.7 million, respectively, of noncontrolling interest in the accompanying consolidated balance sheets were attributable to the Royalty Trusts. The Royalty Trusts' assets and liabilities, after considering the effects of intercompany eliminations, included in the accompanying consolidated balance sheets at December 31, 2012 and 2011 consisted of the following (in thousands):

	December 31,	
	2012	2011
Cash and cash equivalents(1)	$7,445	$3,151
Accounts receivable	28,596	18,357
Derivative contracts	10,286	1,499
Total current assets	46,327	23,007
Investment in royalty interests(2)	1,325,942	858,795
Less: accumulated depletion	(103,746)	(24,404)
	1,222,196	834,391
Derivative contracts	7,660	5,668
Total assets	$1,276,183	$863,066
Accounts payable and accrued expenses	$1,101	$486
Total liabilities	$1,101	$486

(1) Includes $3.0 million and $2.0 million held by the trustee at December 31, 2012 and 2011, respectively, as reserves for future general and administrative expenses.

(2) Investment in royalty interests is included in oil and natural gas properties in the accompanying consolidated balance sheets, and was determined by allocating the historical net book value of the Company's full cost pool based on the fair value of each Royalty Trust's royalty interests relative to the fair value of the Company's full cost pool.

The Company sold Mississippian Trust I and Permian Trust common units it owned in transactions exempt from registration pursuant to Rule 144 under the Securities Act during the year ended December 31, 2012 for total proceeds of $139.4 million. The unit sales were accounted for as equity transactions with no gain or loss recognized. The Company continues to be the primary beneficiary of the Royalty Trusts, as discussed above, and, accordingly, continues to consolidate the activities of the Royalty Trusts. The Company's beneficial interests in the Royalty Trusts at December 31, 2012 and 2011 were as follows:

December 31,

	2012	2011
Mississippian Trust I	26.9 %	38.4 %
Permian Trust	30.5 %	34.3 %
Mississippian Trust II	39.9 %	N/A

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Piñon Gathering Company, LLC. The Company has a gas gathering and operations and maintenance agreement with Piñon Gathering Company, LLC ("PGC") through June 30, 2029. Under the gas gathering agreement, the Company is required to compensate PGC for any throughput shortfalls below a required minimum volume. See Note 16 for amounts due in future periods based on minimum volume requirements under this agreement. By guaranteeing a minimum throughput, the Company absorbs the risk that lower than projected volumes will be gathered by the gathering system. Therefore, PGC is a VIE. Other than as required under the gas gathering and operations and maintenance agreements, the Company has not provided any support to PGC. While the Company operates the assets of PGC as directed under the operations and management agreement, the member and managers of PGC have the authority to directly control PGC and make substantive decisions regarding PGC's activities including terminating the Company as operator without cause. As the Company does not have the ability to control the activities of PGC that most significantly impact PGC's economic performance, the Company is not the primary beneficiary of PGC. Therefore, the results of PGC's activities are not consolidated into the Company's financial statements.

The amounts due from and due to PGC as of December 31, 2012 and 2011 included in the accompanying consolidated balance sheets are as follows (in thousands):

	December 31,	
	2012	2011
Accounts receivable due from PGC	$1,976	$3,205
Accounts payable due to PGC	$8,444	$4,603

5. Fair Value Measurements

The Company measures and reports certain assets and liabilities on a fair value basis and has classified and disclosed its fair value measurements using the following levels of the fair value hierarchy:

Level 1	Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability.
Level 3	Measurement based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable for objective sources (i.e., supported by little or no market activity).

Assets and liabilities that are measured at fair value are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values, stated below, considers the market for the Company's financial assets and liabilities, the associated credit risk and other factors. The Company considers active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The Company has assets and liabilities classified as Level 1, Level 2 and Level 3, as described below.

Level 1 Fair Value Measurements

Restricted deposits. The fair value of restricted deposits invested in mutual funds or municipal bonds is based on quoted market prices. For restricted deposits held in savings accounts, carrying value approximates fair value.

Investments. The fair value of investments, consisting of assets attributable to the Company's deferred compensation plan, is based on quoted market prices. Investments are included in other assets in the accompanying consolidated balance sheets.

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Level 2 Fair Value Measurements

Derivative contracts. The fair value of the Company's oil and natural gas fixed price swaps, oil and natural gas collars and interest rate swap are based upon inputs that are either readily available in the public market, such as oil and natural gas futures prices, volatility factors, interest rates and discount rates, or can be corroborated from active markets. Fair value is determined through the use of a discounted cash flow model or option pricing model using the applicable inputs, discussed above. The Company applies a weighted average credit default risk rating factor for its counterparties or gives effect to its credit default risk rating, as applicable, in determining the fair value of these derivative contracts. Credit default risk ratings are based on current published credit default swap rates.

Level 3 Fair Value Measurements

Derivative contracts. The fair value of the Company's oil basis swaps are based upon quotes obtained from counterparties to the derivative contracts. These values are reviewed internally for reasonableness through the use of a discounted cash flow model using non-exchange traded regional pricing information. Additionally, the Company applies a weighted average credit default risk rating factor for its counterparties or gives effect to its credit risk, as applicable, in determining the fair value of these derivative contracts. The significant unobservable input used in the fair value measurement of the Company's oil basis swaps is the estimate of future oil basis differentials. Significant increases (decreases) in oil basis differentials could result in a significantly higher (lower) fair value measurement. At December 31, 2012, derivative contracts that were valued using Level 3 inputs consisted of oil basis swaps with a fair value of $(0.5) million. Prices of future oil basis differentials used in the fair value measurement ranged from $10.00 per barrel to $21.98 per barrel and had a weighted average value of $14.74 per barrel.

The following tables summarize the Company's assets and liabilities measured at fair value on a recurring basis by the fair value hierarchy (in thousands):

December 31, 2012

	Fair Value Measurements			Netting(1)	Assets/Liabilities at Fair Value
	Level 1	Level 2	Level 3		
Assets					
Restricted deposits	$27,947	$—	$—	$—	$ 27,947
Commodity derivative contracts	—	130,220	183	(35,764)	94,639
Investments	10,348	—	—	—	10,348
	$38,295	$130,220	$183	$(35,764)	$ 132,934
Liabilities					
Commodity derivative contracts	$—	$107,321	$695	$(35,764)	$ 72,252
Interest rate swap	—	2,395	—	—	2,395
	$—	$109,716	$695	$(35,764)	$ 74,647

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December 31, 2011

	Fair Value Measurements Level 1	Level 2	Level 3	Netting(1)	Assets/Liabilities at Fair Value
Assets					
Restricted deposits	$27,912	$—	$—	$—	$ 27,912
Commodity derivative contracts	—	62,746	397	(32,662)	30,481
Investments	7,138	—	—	—	7,138
	$35,050	$62,746	$397	$(32,662)	$ 65,531
Liabilities					
Commodity derivative contracts	$—	$182,694	$4,650	$(32,662)	$ 154,682
Interest rate swap	—	10,448	—	—	10,448
	$—	$193,142	$4,650	$(32,662)	$ 165,130

(1)Represents the impact of netting assets and liabilities with counterparties with which the right of offset exists.

The table below sets forth a reconciliation of the Company's assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the years ended December 31, 2010, 2011 and 2012 (in thousands):

	Commodity Derivative Contracts	Interest Rate Swaps	Total
Balance of Level 3 at January 1, 2010	$46,153	$(8,299)	$37,854
Total realized and unrealized gains (losses)	(50,872)	(16,540)	(67,412)
Purchases	23,196	—	23,196
Settlements (received) paid	(224,337)	8,145	(216,192)
Balance of Level 3 at December 31, 2010	(205,860)	(16,694)	(222,554)
Total realized and unrealized gains (losses)	44,075	(3,168)	40,907
Settlements paid	50,713	9,414	60,127
Transfers(1)	106,820	10,448	117,268
Balance of Level 3 at December 31, 2011	(4,252)	—	(4,252)
Total realized and unrealized gains (losses)	(5,460)	—	(5,460)
Purchases	5,697	—	5,697
Settlements paid	3,503	—	3,503
Balance of Level 3 at December 31, 2012	$(512)	$—	$(512)

(1) Fair values related to the Company's oil and natural gas fixed price swaps, natural gas collars and interest rate swap were transferred from Level 3 to Level 2 in the fourth quarter of 2011 due to enhancements to the Company's internal valuation process, including the use of observable inputs to assess the fair value. During the years ended December 31, 2012 and 2010, the Company did not have any transfers between Level 1, Level 2 or Level 3 fair value measurements. The Company's policy is to recognize transfers between fair value hierarchy levels as of the end of the quarterly reporting period in which the event or change in circumstances causing the transfer occurred.

Unrealized losses of $0.5 million on the Company's Level 3 commodity derivative contracts outstanding at December 31, 2012 have been included in (gain) loss on derivative contracts in the accompanying consolidated statement of operations for the year ended December 31, 2012.

See Note 14 for further discussion of the Company's derivative contracts.

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Fair Value of Financial Instruments

The Company measures the fair value of its senior notes using pricing for the Company’s senior notes that is readily available in the public market. The Company classifies these inputs as Level 2 in the fair value hierarchy. The estimated fair values and carrying values of the Company’s senior notes at December 31, 2012 and 2011 were as follows (in thousands):

	December 31, 2012		December 31, 2011	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Senior Floating Rate Notes due 2014	$—	$—	$339,381	$350,000
9.875% Senior Notes due 2016(1)	392,913	356,657	396,568	354,579
8.0% Senior Notes due 2018	790,313	750,000	765,000	750,000
8.75% Senior Notes due 2020(2)	490,500	444,127	475,875	443,568
7.5% Senior Notes due 2021(3)	1,257,250	1,179,328	909,000	900,000
8.125% Senior Notes due 2022	823,125	750,000	—	—
7.5% Senior Notes due 2023(4)	882,750	820,971	—	—

(1)Carrying value is net of $8,843 and $10,921 discount at December 31, 2012 and 2011, respectively.
(2)Carrying value is net of $5,873 and $6,432 discount at December 31, 2012 and 2011, respectively.
(3)Carrying value includes a premium of $4,328 at December 31, 2012 applicable to notes issued in August 2012.
(4)Carrying value is net of $4,029 discount at December 31, 2012.

The carrying value of the Company’s mortgage note payable at December 31, 2011 approximated fair value based on rates applicable to similar instruments. See Note 13 for discussion of the Company’s long-term debt, including the purchase and redemption of all outstanding Senior Floating Rate Notes due 2014 (the “Senior Floating Rate Notes”) and the issuance of the 8.125% Senior Notes due 2022, additional 7.5% Senior Notes due 2021 and 7.5% Senior Notes due 2023 (collectively, the “2012 Senior Notes”), all of which occurred during 2012.

Allocation of Purchase Price in Business Combinations

The estimated fair values of assets acquired and liabilities assumed in business combinations are based on market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk-adjusted discount rates. See Note 3 for additional information regarding the Company’s acquisitions.

Impairment Assessments

As deemed necessary based on events in the fourth quarter of 2012, the Company analyzed its gas treating plants and CO_2 compression facilities for impairment. Estimated fair values of these assets were calculated using a discounted cash flow method, under which estimated future cash flows were calculated based on management’s expectations for the future use of these assets and estimates of future natural gas production and discounted at a risk-adjusted rate. See Note 8 for further discussion of these impairment assessments.

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6. Accounts Receivable

A summary of accounts receivable is as follows (in thousands):

	December 31,	
	2012	2011
Oil and natural gas sales	$215,450	$134,491
Joint interest billing	202,405	49,688
Oil and natural gas services	21,186	18,798
Insurance receivable	4,590	—
Production tax credits	2,265	3,331
Related party	978	1,645
Other	4,267	2,289
	451,141	210,242
Less: allowance for doubtful accounts	(5,635)	(3,906)
Total accounts receivable, net	$445,506	$206,336

The following table presents the balance and activity in the allowance for doubtful accounts for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Allowance for doubtful accounts at January 1	$3,906	$1,503	$3,590
Additions charged to costs and expenses	1,735	2,511	129
Deductions(1)	(6)	(108)	(2,216)
Allowance for doubtful accounts at December 31	$5,635	$3,906	$1,503

(1) Deductions represent write-off of receivables and collections of amounts for which an allowance had previously been established.

During 2008, the Company established an allowance of $1.5 million for the outstanding balance from a customer in bankruptcy. During 2010, the Company received approximately $0.7 million from this customer and wrote off the remaining $0.8 million balance for a total reduction of the allowance of $1.5 million. During 2011, the Company established an allowance of $2.5 million for amounts subject to ongoing disputes and contract negotiations.

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7. Property, Plant and Equipment

Property, plant and equipment consists of the following (in thousands):

	December 31,	
	2012	2011
Oil and natural gas properties		
Proved(1)	$12,262,921	$8,969,296
Unproved	865,863	689,393
Total oil and natural gas properties	13,128,784	9,658,689
Less accumulated depreciation, depletion and impairment	(5,231,182)	(4,791,534)
Net oil and natural gas properties capitalized costs	7,897,602	4,867,155
Land	17,927	14,196
Non-oil and natural gas equipment(2)	643,370	668,391
Buildings and structures	205,349	133,147
Total	866,646	815,734
Less accumulated depreciation and amortization	(284,271)	(293,465)
Other property, plant and equipment, net	582,375	522,269
Total property, plant and equipment, net	$8,479,977	$5,389,424

(1) Includes cumulative capitalized interest on oil and natural gas properties of $11.7 million and $1.6 million at December 31, 2012 and 2011, respectively.

(2) Includes cumulative capitalized interest of approximately $11.4 million and $6.7 million at December 31, 2012 and 2011, respectively.

There was no full cost ceiling impairment during any of the years ended December 31, 2012, 2011 or 2010. Cumulative full cost ceiling limitation impairment charges of $3.5 billion at both December 31, 2012 and 2011 were included in accumulated depreciation, depletion and impairment for oil and natural gas properties in the accompanying consolidated balance sheets. See Note 8 for discussion of impairment of non-oil and natural gas property, plant and equipment.

The average rates used for depreciation and depletion of oil and natural gas properties were $16.93 per Boe in 2012, $13.57 per Boe in 2011 and $13.24 per Boe in 2010.

Costs Excluded from Amortization

Costs associated with unproved properties of $865.9 million as of December 31, 2012 were excluded from amounts subject to amortization. The following table summarizes the costs, by year incurred, related to unproved properties and pipe inventory, which were excluded from oil and natural gas properties subject to amortization at December 31, 2012 (in thousands):

		Year Cost Incurred			
	Total	2012	2011	2010	2009 and Prior
Property acquisition	$856,290	$377,185	$76,754	$286,758	$115,593
Exploration(1)	81,940	57,579	5,846	6,285	12,230
Total costs incurred	$938,230	$434,764	$82,600	$293,043	$127,823

(1) Includes $72.4 million of pipe inventory costs incurred ($54.9 million in 2012, $2.3 million in 2011, $5.1 million in 2010 and $10.1 million in 2009 and prior years).

The Company expects to complete the majority of the evaluation activities within 10 years from the applicable date of acquisition, contingent on the Company’s capital expenditures and drilling program. In addition, the Company’s internal engineers evaluate all properties on at least an annual basis.

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8. Impairment

Gas Treating Plants. In conjunction with the Company's substantial completion, in the fourth quarter of 2012, of the Century Plant, a CO_2 treatment plant in Pecos County, Texas (the "Century Plant"), and associated compression and pipeline facilities that it constructed pursuant to an agreement with Occidental Petroleum Corporation ("Occidental"), and resulting diversion of the Company's high CO_2 natural gas production from its legacy gas treating plants to the Century Plant, the Company evaluated its legacy gas treating plants and CO_2 compression facilities for impairment. 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 legacy gas treating plants and CO_2 compression facilities in west Texas will be limited, and accordingly, recorded a $79.3 million impairment of its gas treating plants and CO_2 compression facilities.

Rigs. As a result of the Company's agreement to sell the Permian Properties, the Company performed an impairment assessment of its drilling rigs as of December 31, 2012 by calculating the estimated future cash flows to be generated by the rigs and their related assets. As the undiscounted future cash flows were in excess of the assets' carrying value, no impairment was indicated.

Other Property, Plant and Equipment. The Company recorded a $1.3 million impairment in 2012 due to the write-off of certain software costs and a $2.8 million impairment in 2011 on certain natural gas compressors due to the determination that their future use was limited.

9. Goodwill

At December 31, 2011, the Company had $235.4 million of goodwill as a result of the excess consideration over the fair value of net assets acquired in the Arena Acquisition. Goodwill recorded in the Arena Acquisition was primarily attributable to operational and cost synergies realized from the acquisition by using the Company's presence in the Permian Basin, its Fort Stockton, Texas service base and its existing rig ownership to increase its drilling and oil production from the assets acquired. Purchase price adjustments of $1.0 million were recorded during 2011 resulting in an increase to goodwill. The Company assigned the goodwill to its exploration and production segment, which is the reporting unit for impairment testing purposes. The Company's annual evaluation of goodwill was completed as of July 1, 2012. As the reporting unit's anticipated future cash flows were significantly greater than the reporting unit's carrying value, no impairment was recognized at that time. In addition to performing an annual impairment assessment, the Company monitors potential impairment indicators throughout the year.

In December 2012, the Company entered into an agreement to sell the Permian Properties which the Company determined to be a triggering event as the Permian Properties are included in the exploration and production segment, the reporting unit to which goodwill was assigned. As such, an impairment test was performed as of December 31, 2012. Primarily as a result of a decrease in the Company's probable reserves as of December 31, 2012, which are one of the significant components in the determination of the fair value of the reporting unit, the carrying value of the reporting unit exceeded the fair value. Probable reserves used in the reporting unit fair value calculation decreased due to their reclassification to possible reserves as a result of the Company's year end evaluation of drilling results across its acreage in the Mississippian formation. Possible reserves are not included in the fair value calculation of the reporting unit. The Company performed step two of the impairment test which indicated the entire balance of goodwill was impaired. As a result, the Company recorded an impairment of the full carrying amount of goodwill of $235.4 million at December 31, 2012, which is included in impairment in the accompanying consolidated statements of operations.

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10. Other Assets

Other assets consist of the following (in thousands):

	December 31, 2012	2011
Debt issuance costs, net of amortization	$83,643	$51,724
Notes receivable on asset retirement obligations	11,433	—
Investments	10,348	7,138
Production tax credit receivable	6,313	7,665
Lease broker advances	—	13,086
Development advance	—	16,777
Other	4,568	2,232
Total other assets	$116,305	$98,622

11. Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses consist of the following (in thousands):

	December 31, 2012	2011
Accounts payable and other accrued expenses	$461,067	$313,901
Accrued interest	92,125	53,388
Production payable	97,245	59,825
Drilling advances	68,742	36,637
Payroll and benefits	29,811	26,402
Convertible perpetual preferred stock dividends	16,572	16,572
Related party	982	59
Total accounts payable and accrued expenses	$766,544	$506,784

12. Construction Contracts

Century Plant. At December 31, 2012, the Company had substantially completed construction of the Century Plant and associated compression and pipeline facilities pursuant to an agreement with Occidental. The Company constructed the Century Plant for a contract price of $796.3 million, including agreed upon change orders and scope revisions, which was paid by Occidental to the Company through periodic cost reimbursements based upon the percentage of the project completed. Upon substantial completion of construction in late 2012, Occidental took ownership and began operating the plant for the purpose of separating and removing CO_2 from the delivered natural gas stream. With substantial completion of the contract in the fourth quarter of 2012, the Company recognized construction contract revenue and construction contract costs equal to the revised contract price of $796.3 million, which are included in the accompanying consolidated statements of operations. The Company recorded additions totaling $180.0 million (including $50.0 million and $25.0 million, respectively, during the years ended December 31, 2012 and 2011) to its oil and natural gas properties for the loss identified based on costs incurred in excess of contract amounts. Billings and estimated contract loss in excess of costs incurred of $15.5 million, representing costs expected to be incurred in final stages of construction, and $43.3 million at December 31, 2012 and 2011, respectively, is reported as a current liability in the accompanying consolidated balance sheets.

Pursuant to a 30-year treating agreement executed simultaneously with the construction agreement, Occidental will remove CO_2 from the Company's delivered natural gas production volumes. 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. See Note 16 for additional discussion of this requirement. The Company retains all methane gas from the natural gas it delivers to the Century Plant.

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Transmission Expansion Projects. The Company entered into a construction services agreement in November 2011 to manage the design, engineering and construction of a series of transmission expansion and upgrade projects in northern Oklahoma. Under the terms of the agreement, the Company will be reimbursed for costs incurred on these projects up to approximately $23.3 million, plus any subsequently agreed-upon revisions. Construction on these projects began in 2012 with the final project expected to be completed in the first quarter of 2013. Costs in excess of billings on these projects of $11.2 million at December 31, 2012 is included in current assets in the accompanying consolidated balance sheets. There were no amounts related to these projects included in the accompanying consolidated balance sheets at December 31, 2011.

13. Long-Term Debt

Long-term debt consists of the following (in thousands):

	December 31,	
	2012	2011
Senior credit facility	$—	$—
Senior Fixed Rate Notes		
9.875% Senior Notes due 2016, net of $8,843 and $10,921 discount, respectively	356,657	354,579
8.0% Senior Notes due 2018	750,000	750,000
8.75% Senior Notes due 2020, net of $5,873 and $6,432 discount, respectively	444,127	443,568
7.5% Senior Notes due 2021, including a premium of $4,328 at December 31, 2012	1,179,328	900,000
8.125% Senior Notes due 2022	750,000	—
7.5% Senior Notes due 2023, net of $4,029 discount at December 31, 2012	820,971	—
Senior Floating Rate Notes due 2014	—	350,000
Mortgage note payable	—	16,029
Total debt	4,301,083	2,814,176
Less: current maturities of long-term debt	—	1,051
Long-term debt	$4,301,083	$2,813,125

Senior Credit Facility

The senior credit facility is available to be drawn on subject to limitations based on its terms and certain financial covenants. On March 29, 2012, the senior credit facility was amended and restated to, among other things, (a) increase the borrowing base to $1.0 billion from $790.0 million, (b) allow for the incurrence or issuance of additional debt (including up to $750.0 million of unsecured debt to finance the cash portion of the Dynamic purchase price and related costs and expenses), (c) permit the Company to designate certain of its subsidiaries as unrestricted subsidiaries, and (d) effective on and after June 30, 2012, establish the financial covenants as maintaining agreed upon levels for (i) ratio of total net debt to EBITDA, which may not exceed 4.5:1.0 at each quarter end, calculated using the last four completed fiscal quarters and (ii) ratio of current assets to current liabilities, which must be at least 1.0:1.0 at each quarter end. If no amounts are drawn under the senior credit facility when calculating the ratio of total net debt to EBITDA, the Company's debt is reduced by its cash balance in excess of $10.0 million. In the current ratio calculation, any amounts available to be drawn under the senior credit facility are included in current assets, and unrealized assets and liabilities resulting from mark-to-market adjustments on the Company's derivative contracts are disregarded. The senior credit facility matures in March 2017.

The senior credit facility contains various covenants that limit the ability of the Company and certain of its subsidiaries to grant certain liens; make certain loans and investments; make distributions; redeem stock; redeem or prepay debt; merge or consolidate with or into a third party; or engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets. Additionally, the senior credit facility limits the ability of the Company and certain of its subsidiaries to incur additional indebtedness with certain exceptions. As of and during the year ended

December 31, 2012, the Company was in compliance with all applicable financial covenants under the senior credit facility.

The obligations under the senior credit facility are guaranteed by certain Company subsidiaries and are secured by first priority liens on all shares of capital stock of certain of the Company's material present and future subsidiaries; certain intercompany debt of the Company; and substantially all of the Company's assets, including proved oil and natural gas reserves representing at least 80.0% of the discounted present value (as defined in the senior credit facility) of proved oil and natural gas reserves considered by the lenders in determining the borrowing base for the senior credit facility.

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At the Company's election, interest under the senior credit facility is determined by reference to (a) the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.75% and 2.75% per annum or (b) the "base rate," which is the highest of (i) the federal funds rate plus 0.5%, (ii) the prime rate published by Bank of America or (iii) the Eurodollar rate (as defined in the senior credit facility) plus 1.00% per annum, plus, in each case under scenario (b), an applicable margin between 0.75% and 1.75% per annum. Interest is payable quarterly for base rate loans and at the applicable maturity date for LIBOR loans, except that if the interest period for a LIBOR loan is six months, interest is paid at the end of each three-month period. During the year ended December 31, 2012, the Company paid commitment fees of 0.5% on the available portion of the senior credit facility as there have been no amounts outstanding under the senior credit facility during 2012. The average annual interest rate paid on amounts outstanding under the senior credit facility was 2.69% and 2.70%, respectively, for the years ended December 31, 2011 and 2010.

Borrowings under the senior credit facility may not exceed the lower of the borrowing base or the committed amount. In August 2012, the borrowing base was reduced to $775.0 million from $1.0 billion as a result of the issuance of the 7.5% Senior Notes due 2023 and additional 7.5% Senior Notes due 2021, as discussed below. The Company's borrowing base is redetermined in April and October of each year, and was reaffirmed at $775.0 million in October 2012. The next borrowing base redetermination will be in April 2013. With respect to each redetermination, the administrative agent and the lenders under the senior credit facility consider several factors, including the Company's proved reserves and projected cash requirements, and make assumptions regarding, among other things, oil and natural gas prices and production. Because the value of the Company's proved reserves is a key factor in determining the amount of the borrowing base, changing commodity prices and the Company's success in developing reserves may affect the borrowing base. The Company at times incurs additional costs related to the senior credit facility as a result of amendments to the credit agreement and changes to the borrowing base. During 2012, additional costs of approximately $7.5 million were incurred. These costs have been deferred, and are included in other assets in the accompanying consolidated balance sheets and are being amortized to interest expense over the term of the senior credit facility.

At December 31, 2012, the Company had no amount outstanding under the senior credit facility and $30.2 million in outstanding letters of credit, which reduce the availability under the senior credit facility on a dollar-for-dollar basis.

Senior Fixed Rate Notes

The Company's unsecured senior fixed rate notes ("Senior Fixed Rate Notes") bear interest at a fixed rate per annum, payable semi-annually, with the principal due upon maturity. Certain of the Senior Fixed Rate Notes were issued at a discount or a premium. The discount or premium is amortized to interest expense over the term of the respective senior notes. The Senior Fixed Rate Notes are redeemable, in whole or in part, prior to their maturity at specified redemption prices and are jointly and severally guaranteed unconditionally, in full, on an unsecured basis by certain of the Company's wholly owned subsidiaries. See Note 24 for condensed financial information of the subsidiary guarantors.

Debt issuance costs of $94.1 million incurred in connection with the offerings of the Senior Fixed Rate Notes and any subsequent registered exchanges are included in other assets in the accompanying consolidated balance sheets and are being amortized to interest expense over the term of the respective senior notes.

2011 Activity. In March 2011, the Company issued $900.0 million of unsecured 7.5% Senior Notes due 2021 to qualified institutional buyers eligible under Rule 144A of the Securities Act and to persons outside the United States under Regulation S under the Securities Act. Net proceeds from the offering were used to fund the tender offer for, and subsequent redemption of, the 8.625% Senior Notes due 2015, described below and to repay borrowings under the Company's senior credit facility.

In March 2011, the Company purchased approximately 94.5%, or $614.2 million, of the aggregate principal amount of its 8.625% Senior Notes due 2015 pursuant to a tender offer. In April 2011, the Company redeemed the remaining outstanding $35.8 million aggregate principal amount of its 8.625% Senior Notes due 2015. All holders whose notes were purchased or redeemed received accrued and unpaid interest from October 1, 2010. The premium paid to purchase these notes and the unamortized debt issuance costs associated with the notes, totaling $38.2 million, were recorded as a loss on extinguishment of debt in the accompanying consolidated statements of operations for the year ended December 31, 2011.

In November 2011, pursuant to an exchange offer, the Company replaced substantially all of the 7.5% Senior Notes due 2021 with 7.5% Senior Notes due 2021 that are registered under the Securities Act. The exchange offer did not result in the incurrence of any additional indebtedness.

2012 Activity. In 2012, the Company completed offerings of the 2012 Senior Notes to qualified institutional buyers eligible under Rule 144A of the Securities Act and to persons outside the United States under Regulation S under the Securities Act. The Company incurred $41.0 million of debt issuance costs in connection with the 2012 Senior Notes offerings. These costs are included in other assets in the accompanying consolidated balance sheets and are being amortized to interest expense over the term of the respective senior notes.

In April 2012, the Company issued $750.0 million of unsecured 8.125% Senior Notes due 2022. 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.

In August 2012, the Company issued $825.0 million of unsecured 7.5% Senior Notes due 2023 at 99.5% of par and $275.0 million of additional unsecured 7.5% Senior Notes due 2021 at 101.625% of par, plus accrued interest from March 15, 2012. The Company received net proceeds from this offering of approximately $1.1 billion, after deducting offering expenses and excluding accrued interest received. The net proceeds of the offering were used to fund the Company's tender offer for, and subsequent redemption of, its Senior Floating Rate Notes, discussed under Senior Floating Rate Notes due 2014 below, to fund the Company's capital expenditures and for general corporate purposes.

In November 2012, pursuant to exchange offers, the Company replaced the 2012 Senior Notes with equivalent senior notes that are registered under the Securities Act. The exchange offers did not result in the incurrence of any additional indebtedness.

Indentures. The indentures governing the Company's senior notes contain covenants which restrict the Company's ability to take a variety of actions, including limitations on the incurrence of indebtedness, payment of dividends, investments, asset sales, certain asset purchases, transactions with related parties and consolidations or mergers. As of and during the year ended December 31, 2012, the Company was in compliance with all of the covenants contained in the indentures governing the senior notes.

Senior Floating Rate Notes Due 2014

The Company's Senior Floating Rate Notes were issued in May 2008 and bore interest at LIBOR plus 3.625%. On August 6, 2012, the Company announced a cash tender offer to purchase any and all of the outstanding $350.0 million aggregate principal amount of its Senior Floating Rate Notes. The Company purchased approximately 94.3%, or $329.9 million, of the aggregate principal amount of its Senior Floating Rate Notes pursuant to the tender offer, which expired on August 31, 2012. On September 4, 2012, the Company redeemed the remaining outstanding $20.1 million aggregate principal amount of its Senior Floating Rate Notes. All holders whose notes were purchased in the tender offer or redemption received accrued and unpaid interest from July 1, 2012 through the date of purchase. The premium paid to purchase these notes and the unamortized debt issuance costs associated with the notes, totaling $3.1 million, were recorded as a loss on extinguishment of debt and included in the accompanying consolidated statements of operations for the year ended December 31, 2012.

Mortgage Note Payable

The debt incurred to purchase the downtown Oklahoma City property that serves as the Company's corporate headquarters was fully secured by a mortgage on one of the buildings located on the property. In May 2012, the Company paid the outstanding $15.8 million principal balance on the note underlying the mortgage.

Maturities of Long-Term Debt

Aggregate maturities of long-term debt, excluding discounts, are $365.5 million in 2016 and $4.0 billion thereafter.

14. Derivatives

The Company has not designated any of its derivative contracts as hedges for accounting purposes. The Company records all derivative contracts, which include commodity derivatives and an interest rate swap, at fair value. Changes in derivative contract fair values are recognized in earnings. Cash settlements and valuation gains and losses are included in (gain) loss on derivative contracts for commodity derivative contracts and in interest expense for interest rate swaps in the consolidated statement of operations. Commodity derivative contracts are settled on a monthly or quarterly basis. Settlements on interest rate swaps occur quarterly. Derivative assets and liabilities arising from the Company’s derivative contracts with the same counterparty that provide for net settlement are reported on a net basis in the consolidated balance sheet.

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Commodity Derivatives. The Company is exposed to commodity price risk, which impacts the predictability of its cash flows from the sale of oil and natural gas. The Company seeks to manage this risk through the use of commodity derivative contracts. These derivative contracts allow the Company to limit its exposure to commodity price volatility on a portion of its forecasted oil and natural gas sales. None of the Company’s derivative contracts may be terminated early solely as a result of a downgrade in the credit rating of a party to the contract. At December 31, 2012, the Company’s commodity derivative contracts consisted of fixed price swaps, collars and basis swaps, which are described below:

Fixed price swaps	The Company receives a fixed price for the contract and pays a floating market price to the counterparty over a specified period for a contracted volume.
Collars	Two-way collars contain a fixed floor price (put) and a fixed ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party. Three-way collars have two fixed floor prices (a purchased put and a sold put) and a fixed ceiling price (call). The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be New York Mercantile Exchange plus the difference between the purchased put and the sold put strike price. The call establishes a maximum price (ceiling) the Company will receive for the volumes under the contract.
Basis swaps	The Company receives a payment from the counterparty if the settled price differential is greater than the stated terms of the contract and pays the counterparty if the settled price differential is less than the stated terms of the contract, which guarantees the Company a price differential for oil and natural gas from a specified delivery point.

Interest Rate Swaps. The Company is exposed to interest rate risk on long-term fixed and variable interest rate borrowings. Fixed rate debt, where the interest rate is fixed over the life of the instrument, exposes the Company to (i) changes in market interest rates reflected in the fair value of the debt and (ii) the risk that the Company may need to refinance maturing debt with new debt at a higher rate. Variable rate debt, where the interest rate fluctuates, exposes the Company to short-term changes in market interest rates as the Company’s interest obligations on these instruments are periodically redetermined based on prevailing market interest rates, primarily LIBOR and the federal funds rate.

The Company has a $350.0 million notional interest rate swap agreement, which effectively fixed the variable interest rate on the Senior Floating Rate Notes at an annual rate of 6.69% for periods prior to the Company’s purchase of the Senior Floating Rate Notes in the third quarter of 2012. The interest rate swap terminates April 1, 2013 and has not been designated as a hedge.

Derivatives Agreements with Royalty Trusts. Effective April 1, 2011, August 1, 2011 and April 1, 2012, the Company entered into derivatives agreements with the Mississippian Trust I, Permian Trust and Mississippian Trust II, respectively, to provide each Royalty Trust with the economic effect of certain oil and natural gas derivative contracts entered into by the Company with third parties. The underlying commodity derivative contracts cover volumes of oil and natural gas production through December 31, 2015, March 31, 2015 and December 31, 2014 for the Mississippian Trust I, Permian Trust and Mississippian Trust II, respectively. Under these arrangements, the Company will pay the Royalty Trusts amounts it receives from its counterparties in accordance with the underlying contracts, and the Royalty Trusts will pay the Company any amounts that the Company is required to pay its counterparties under such contracts.

Substantially concurrent with the execution of the respective derivatives agreements, the Company novated certain of the derivatives contracts underlying the derivatives agreements to each of the Permian Trust and Mississippian Trust II. As a party to these contracts, the Permian Trust and Mississippian Trust II will receive payment directly from the counterparty and pay any amounts owed directly to the counterparty. To secure its obligations under the respective derivatives contracts novated to it, each of the Permian Trust and Mississippian Trust II granted the counterparties liens on the royalty interests held by each respective trust. Under the derivatives agreements, as development wells are drilled for the benefit of the Permian Trust and Mississippian Trust II, the Company will have the right, under certain circumstances, to assign or novate to the Permian Trust and Mississippian Trust II additional derivative contracts. In April 2012, the Company novated to the Permian Trust additional derivative contracts underlying the derivatives agreement.

All contracts underlying the derivatives agreements with the Royalty Trusts, including those novated to the Permian Trust and Mississippian Trust II, have been included in the Company's consolidated derivative disclosures. See Note 4 for additional discussion of the Royalty Trusts.

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Fair Value of Derivatives. The following table presents the fair value of the Company's derivative contracts as of December 31, 2012 and 2011 on a gross basis without regard to same-counterparty netting (in thousands):

		December 31,	
Type of Contract	Balance Sheet Classification	2012	2011
Derivative assets			
Oil price swaps	Derivative contracts—current	$88,052	$6,095
Natural gas price swaps	Derivative contracts—current	—	6,585
Oil basis swaps	Derivative contracts—current	183	—
Natural gas collars	Derivative contracts—current	3,111	313
Diesel price swaps	Derivative contracts—current	—	397
Oil price swaps	Derivative contracts—noncurrent	37,983	48,718
Oil collars—three way	Derivative contracts—noncurrent	190	—
Natural gas collars	Derivative contracts—noncurrent	884	1,035
Derivative liabilities			
Oil price swaps	Derivative contracts—current	(31,991)	(116,243)
Oil basis swaps	Derivative contracts—current	(695)	—
Oil collars—two way	Derivative contracts—current	(103)	—
Diesel price swaps	Derivative contracts—current	—	(41)
Interest rate swap	Derivative contracts—current	(2,395)	(8,475)
Oil price swaps	Derivative contracts—noncurrent	(67,900)	(66,451)
Natural gas basis swaps	Derivative contracts—noncurrent	—	(4,609)
Oil collars—three way	Derivative contracts—noncurrent	(7,327)	—
Interest rate swap	Derivative contracts—noncurrent	—	(1,973)
Total net derivative contracts		$19,992	$(134,649)

Refer to Note 5 for additional discussion of the fair value measurement of the Company's derivative contracts.

The following table summarizes the cash settlements and valuation gain and loss on the Company's commodity derivative contracts and interest rate swaps, which are included in (gain) loss on derivative contracts and interest expense, respectively, in the accompanying consolidated statements of operations for the years ended December 31, 2012, 2011 and 2010 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Commodity Derivatives			
Realized (gain) loss(1)	$(31,718)	$50,713	$(224,337)
Unrealized (gain) loss	$(209,701)	$(94,788)	$275,209
(Gain) loss on commodity derivative contracts	$(241,419)	$(44,075)	$50,872
Interest Rate Swaps			
Realized loss	$9,243	$9,414	$8,145
Unrealized (gain) loss	(8,054)	(6,246)	8,395
Loss on interest rate swaps	$1,189	$3,168	$16,540

(1) The year ended December 31, 2012 includes $59.5 million of net realized gain related to settlements of commodity derivative contracts with contractual maturities after the quarterly period in which they were settled ("early settlements") and a $117.1 million non-cash realized loss on derivative contracts amended in January 2012. The years ended December 31, 2011 and 2010 include $48.1 million ($111.0 million realized gain and $62.9 million realized loss) and $114.5 million of realized gain, respectively, related to early settlements.

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At December 31, 2012, the Company's open commodity derivative contracts consisted of the following:

Oil Price Swaps

	Notional (MBbls)	Weighted Average Fixed Price
January 2013 — December 2013	18,515	$96.24
January 2014 — December 2014	7,511	$92.43
January 2015 — December 2015	5,076	$83.69

Oil Basis Swaps

	Notional (MBbls)	Weighted Average Fixed Price
January 2013 — December 2013	543	$ 13.83

Oil Collars - Two-way

	Notional (MBbls)	Collar Range		
January 2013 — December 2013	168	$80.00	—	$102.50

Oil Collars - Three-way

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

Natural Gas Collars

	Notional (MMcf)	Collar Range		
January 2013 — December 2013	6,858	$3.78	—	$6.71
January 2014 — December 2014	937	$4.00	—	$7.78
January 2015 — December 2015	1,010	$4.00	—	$8.55

15. Asset Retirement Obligations

The following table presents the balance and activity of the asset retirement obligations for the years ended December 31 (in thousands).

	2012	2011	2010
Asset retirement obligations at January 1	$128,116	$119,877	$111,137
Liability incurred upon acquiring and drilling wells	7,479	5,716	17,347
Liability assumed in acquisition	371,365	—	—
Revisions in estimated cash flows	34,654	7,574	(17,017)
Liability settled or disposed in current period	(72,200)	(14,419)	(1,011)
Accretion	28,996	9,368	9,421
Asset retirement obligations at December 31	498,410	128,116	119,877
Less: current portion	118,504	32,906	25,360
Asset retirement obligations, net of current	$379,906	$95,210	$94,517

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Liability assumed in acquisition, liability settled and accretion for the year ended December 31, 2012 include amounts attributable to asset retirement obligations assumed in the acquisitions of oil and natural gas properties in the Gulf of Mexico during the second quarter of 2012. The current year settlements increased significantly due to the higher costs associated with plugging and abandoning the properties in the Gulf of Mexico. Liability settled or disposed for the year ended December 31, 2011 primarily consists of amounts related to the Permian Basin and east Texas properties sold during 2011. The revisions in estimated cash flows for the year ended December 31, 2010 were primarily due to lengthening reserve lives based on higher oil and natural gas prices used to determine reserves relative to prices at the beginning of 2010. At December 31, 2010, asset retirement obligations of $21.8 million related to an offshore platform were moved to current, due to its then anticipated plugging and abandonment in 2011.

16. Commitments and Contingencies

Operating Leases. The Company has obligations under noncancelable operating leases, primarily for office space and equipment used in drilling and services activities. Total rental expense under operating leases for the years ended December 31, 2012, 2011 and 2010 was approximately $2.6 million, $1.5 million and $2.6 million, respectively.

Future minimum payments under noncancelable operating leases (with initial lease terms exceeding one year) as of December 31, 2012 were as follows (in thousands):

Years ending December 31	
2013	$2,694
2014	2,511
2015	2,251
2016	2,018
2017	1,339
	$10,813

Rig Commitments. The Company has contracts with third-party drilling rig operators for the use of their rigs at specified day or footage rates. These commitments are not recorded in the consolidated balance sheets. Minimum future commitments as of December 31, 2012 were $44.2 million for 2013 and $9.7 million for 2014.

Hydraulic Well Fracturing Services Agreements. The Company has third-party hydraulic well fracturing services agreements through early 2014 that contain provisions for the payment of certain termination fees in the event the Company terminates the agreements prior to completion. At December 31, 2012, these potential termination fees were approximately $33.4 million.

Oil and Natural Gas Transportation and Throughput Agreements. The Company has subscribed firm gas transportation service under a transportation service agreement on the Midcontinent Express Pipeline, the term of which continues until March 2019. This commitment is not recorded in the consolidated balance sheets. Under the terms of the agreement, the Company is obligated to pay a demand charge and in exchange, obtains the right to flow natural gas production through this pipeline to more competitive marketing areas. The Company also has oil and natural gas throughput agreements in place, which require fixed fees based on minimum volume requirements for the right to flow oil and natural gas through certain pipelines. The amounts of the required payments related to the transportation and throughput agreements as of December 31, 2012 were as follows (in thousands):

Years ending December 31	
2013	$26,653
2014	19,671
2015	12,977
2016	11,346
2017	11,315

Thereafter	14,105
	$96,067

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Natural Gas Gathering Agreement. The Company has a gas gathering agreement with PGC related to its properties located in the Piñon Field in west Texas. Under the gas gathering agreement, the Company has dedicated its west Texas acreage for priority gathering services through June 30, 2029 and will pay a fee for such services. Pursuant to the gas gathering agreement, the base fee can be reduced if certain criteria are met. The table below presents the base fee contractual obligations under this agreement as of December 31, 2012 (in thousands).

Years ending December 31	
2013	$42,634
2014	42,360
2015	42,153
2016	42,091
2017	41,812
Thereafter	141,775
	$352,825

Treating Agreement. In conjunction with the Century Plant construction agreement, the Company entered into a 30-year treating agreement with Occidental for the removal of CO_2 from the Company's delivered production volumes. Under the agreement, the Company is required to deliver a total of approximately 3,200 Bcf of CO_2 during the agreement period and is required to compensate Occidental to the extent certain minimum annual CO_2 volume requirements are not met. Based upon natural gas production levels in 2012, the Company accrued $8.5 million for amounts related to the Company's shortfall in meeting its 2012 delivery obligations, which was included in production expenses in the accompanying consolidated statements of operations for the year ended December 31, 2012. 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 obligations based on current projected natural gas production levels. 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; however, curtailed drilling due to continued low natural gas prices may result in additional shortfall payments in future periods.

Litigation and Claims. On or about June 27, 2008 and November 6, 2008, there were fires at the Company's Grey Ranch Plant and a nearby compressor station. The Company, as owner of the plant and compressor station, recovered approximately $24.5 million from its insurance carriers for damages caused by the fires. At the time of the fires, the plant was operated by Southern Union Gas Services, Ltd. ("Southern Union Gas"). On June 4, 2010, November 10, 2010, and March 15, 2011, the Company's insurance carriers filed lawsuits against Southern Union Gas and its parent, Southern Union Company (together with Southern Union Gas, "Southern Union") seeking recovery for amounts paid under the Company's insurance policies. Southern Union, in turn, tendered indemnity requests to GRLP, of which the Company is a 50% owner. All three lawsuits have been settled between the Company's insurance carrier and Southern Union; however, Southern Union's indemnification claim against GRLP remains unresolved. GRLP has not accepted or acknowledged any responsibility to indemnify Southern Union. As a result of the settlement of the lawsuits, an estimate of reasonably possible losses associated with these claims is approximately $1.1 million. As a loss is not probable, the Company has not established any reserves relating to these claims. To the extent the Company, as a 50% owner of GRLP, is required to fund any indemnification of Southern Union, it will pursue coverage for such liability under its general liability insurance policy.

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 in the accompanying consolidated balance sheets as of December 31, 2012.

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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 carbon dioxide, or "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.

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

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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.

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

17. Equity

Preferred Stock

The following table presents information regarding the Company's preferred stock (in thousands):

	December 31,	
	2012	2011
Shares authorized	50,000	50,000
Shares outstanding at end of period		
8.5% Convertible perpetual preferred stock	2,650	2,650
6.0% Convertible perpetual preferred stock	2,000	2,000
7.0% Convertible perpetual preferred stock	3,000	3,000

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The Company is authorized to issue 50.0 million shares of preferred stock, $0.001 par value, of which 7.7 million shares are designated as convertible perpetual preferred stock at December 31, 2012 and 2011. All of the outstanding shares of the Company's convertible perpetual preferred stock were issued in private transactions. However, all of the outstanding shares of convertible perpetual preferred stock are freely tradable.

8.5% Convertible perpetual preferred stock. The Company's 8.5% convertible perpetual preferred stock was issued in January 2009. Each share of 8.5% convertible perpetual preferred stock has a liquidation preference of $100.00 and is convertible at the holder's option at any time initially into approximately 12.4805 shares of the Company's common stock, subject to customary adjustments in certain circumstances. Each holder of the convertible perpetual preferred stock is entitled to an annual dividend of $8.50 per share to be paid semi-annually in cash, common stock or a combination thereof, at the Company's election. The 8.5% convertible perpetual preferred stock is not redeemable by the Company at any time. After February 20, 2014, the Company may cause all outstanding shares of the convertible perpetual preferred stock to convert automatically into common stock at the then-prevailing conversion rate if certain conditions are met.

6.0% Convertible perpetual preferred stock. The Company's 6.0% convertible perpetual preferred stock was issued in December 2009. Each share of the 6.0% convertible perpetual preferred stock has a liquidation preference of $100.00 and is entitled to an annual dividend of $6.00 payable semi-annually in cash, common stock or any combination thereof, at the Company's election. The 6.0% convertible perpetual preferred stock is not redeemable by the Company at any time. Each share is initially convertible into approximately 9.2115 shares of the Company's common stock, at the holder's option, subject to customary adjustments in certain circumstances. On December 21, 2014, all outstanding shares of the 6.0% convertible preferred stock will convert automatically into shares of the Company's common stock at the then-prevailing conversion rate as long as all dividends accrued at that time have been paid.

7.0% Convertible perpetual preferred stock. The Company's 7.0% convertible perpetual preferred stock was issued in November 2010. Each share of the 7.0% convertible preferred stock has a liquidation preference of $100.00 per share and became convertible at the holder's option on February 15, 2011, initially into approximately 12.8791 shares of the Company's common stock, subject to customary adjustments in certain circumstances. Beginning on May 15, 2011, the annual dividend on each share of the 7.0% convertible preferred stock is $7.00 payable semi-annually, in cash, common stock or a combination thereof, at the Company's election. The 7.0% convertible perpetual preferred stock is not redeemable by the Company at any time. After November 20, 2015, the Company may cause all outstanding shares of the 7.0% convertible perpetual preferred stock to convert automatically into common stock at the then-prevailing conversion rate if certain conditions are met.

Preferred stock dividends. All dividend payments to date on the Company's 8.5%, 6.0% and 7.0% convertible perpetual preferred stock have been paid in cash. Paid and unpaid dividends included in the calculation of income available to the Company's common stockholders and the Company's basic earnings per share calculation for the years ended December 31, 2012, 2011 and 2010 as presented in the accompanying consolidated statements of operations, are included in tables below (in thousands):

	Dividends Paid	Dividends Unpaid	Total
Year Ended December 31, 2012			
8.5% Convertible perpetual preferred stock	$14,078	$8,447	$22,525
6.0% Convertible perpetual preferred stock	6,500	5,500	12,000
7.0% Convertible perpetual preferred stock	18,375	2,625	21,000
Total	$38,953	$16,572	$55,525
Year Ended December 31, 2011			
8.5% Convertible perpetual preferred stock	$14,078	$8,447	$22,525
6.0% Convertible perpetual preferred stock	6,500	5,500	12,000

7.0% Convertible perpetual preferred stock	18,433	2,625	21,058
Total	$39,011	$16,572	$55,583
Year Ended December 31, 2010			
8.5% Convertible perpetual preferred stock	$14,079	$8,446	$22,525
6.0% Convertible perpetual preferred stock	6,000	6,000	12,000
7.0% Convertible perpetual preferred stock	—	2,917	2,917
Total	$20,079	$17,363	$37,442

Common Stock

The following table presents information regarding the Company's common stock (in thousands):

	December 31,	
	2012	2011
Shares authorized	800,000	800,000
Shares outstanding at end of period	490,359	411,953
Shares held in treasury	1,219	874

In July 2010, in conjunction with stockholder approval of the issuance of shares of Company common stock in connection with the Company's acquisition of Arena, the Company's stockholders approved an amendment to the Company's certificate of incorporation to increase the number of authorized shares of common stock from 400.0 million shares to 800.0 million shares. On July 16, 2010, the Company issued approximately 190.3 million shares of Company common stock as partial consideration for the acquisition of Arena. See Note 3 for further discussion of the Arena Acquisition.

In December 2010, the Company issued approximately 1.8 million shares of Company common stock (of which approximately 0.5 million shares were newly issued and approximately 1.3 million shares were issued from treasury stock) as part of the settlement of a dispute with certain working interest owners. The issuance of the 0.5 million shares resulted in an addition to the Company's additional paid-in capital of $3.4 million, the amount by which the market value of the common stock on the day of issuance exceeded par value. See additional discussion, including the effects on treasury stock and additional paid-in capital, below.

On April 17, 2012, the Company issued approximately 74.0 million shares of SandRidge common stock to satisfy the stock portion of the consideration paid in the Dynamic Acquisition. See Note 3 for further discussion of the Dynamic Acquisition.

Stockholder Rights Plan

On November 19, 2012, the Company's Board of Directors adopted a stockholder rights plan pursuant to which the Board of Directors authorized and declared to stockholders of record on November 29, 2012 a dividend of one preferred share purchase right (the "Right") for each outstanding share of common stock. The Board adopted the rights plan to protect stockholders from coercive or otherwise unfair takeover tactics. The Rights generally become exercisable ten business days after any person or group becomes the beneficial owner of 10%, or 15% in the case of certain institutional investors, ("Acquiring Person") or more of the Company's outstanding common stock. Each Right entitles stockholders to buy one one-thousandth of a share of Series A Junior Participating Preferred Stock ("Series A Preferred Stock"), par value $0.001 per share, at a price of $20.00 per one one-thousandth of a preferred share, subject to adjustment. Holders of Rights (other than the Acquiring Person) are entitled to receive, upon exercise, Series A Preferred Stock, or in lieu thereof, common stock of the Company having a value of twice the Right's then-current exercise price. The Series A Preferred Stock is not redeemable by the Company and has voting privileges and certain dividend and liquidation preferences. The Company may redeem the outstanding Rights at any time prior to any person or group becoming an Acquiring Person at a redemption price of $0.001 per Right, subject to adjustment. At any time after any person or group becomes an Acquiring Person, the Company may exchange all or part of the outstanding Rights for common stock at an exchange ratio of one common share per Right. The Rights will expire on November 19, 2013, unless redeemed or exchanged on an earlier date.

Treasury Stock

The Company makes required statutory tax payments on behalf of employees when their restricted 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. As a result of such transactions, the Company withheld approximately 1.5 million shares having a total value of $11.3 million, and approximately 1.2 million shares having a total value of $10.8 million during the years ended December 31, 2012 and 2011, respectively. These shares were accounted for as treasury stock when withheld, and then immediately retired. The Company withheld approximately 0.8 million shares having a total value of $6.3 million during the year ended December 31, 2010. These shares were accounted for as treasury stock when withheld. In December 2010, the Company retired all shares held as treasury, excluding shares of Company common stock held as assets in a trust for the Company's non-qualified deferred compensation plan, to satisfy tax withholding obligations related to the vesting of restricted stock awards under the Company's incentive compensation plans. Retirement of the treasury shares in December 2010 resulted in a reduction to additional paid-in capital equal to the historical cost of the treasury shares, or approximately $11.3 million.

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In December 2010, the Company finalized the settlement of a dispute with certain working interest owners under two joint operating agreements. As part of the settlement, the Company issued the working interest owners a total of approximately 1.8 million shares of Company common stock. As noted above, approximately 0.5 million of such shares were newly issued and the remaining 1.3 million shares were issued from treasury stock. The historical cost of the treasury shares issued was approximately $14.0 million. The difference between the market price of these shares at the time of issuance and the historical cost resulted in a decrease of the Company’s additional paid-in capital of approximately $5.2 million.

Shares of Company common stock held as assets in a trust for the Company’s non-qualified deferred compensation plan are accounted for as treasury shares. These shares are not included as outstanding shares of common stock in this report. For corporate purposes, including for the purpose of voting at Company stockholder meetings, these shares are considered outstanding and have voting rights, which are exercised by the Company.

Stockholder Receivable

On November 9, 2012, Tom L. Ward, Chief Executive Officer, and the Company entered into a settlement agreement with a stockholder plaintiff relating to a third-party claim under Section 16(b) of the Securities Exchange Act of 1934, as amended. The claim was filed in December 2010 and related to certain transactions involving Company common stock by Mr. Ward in 2008 and 2009. The settlement agreement finds no liability or other wrongdoing under Section 16(b) regarding the transactions in question. Under the settlement agreement, Mr. Ward agreed to pay to the Company $5.0 million in four installments over four years commencing October 2013 and to waive his rights under his indemnification agreement with the Company with respect to this Section 16(b) action. The Company agreed to pay the fees of the plaintiff’s lawyers and paid Mr. Ward’s legal expenses as required under his indemnification agreement.

Based on the nature of the settlement as well as Mr. Ward’s position as an officer of the Company, a $5.0 million receivable was recorded as a component of additional paid-in capital and is included in the accompanying consolidated balance sheets as of December 31, 2012.

Equity Compensation

The Company awards restricted common stock under its long-term incentive compensation plan that vest over specified periods of time, subject to certain conditions, and are valued based upon the market value of common stock on the date of grant. Awards issued prior to 2006 had vesting periods of one, four or seven years. Awards issued during and after 2006 generally have four-year vesting periods. Shares of restricted common stock are subject to restriction on transfer. Unvested restricted stock awards are included in the Company’s outstanding shares of common stock.

For the years ended December 31, 2012, 2011 and 2010, the Company recognized equity compensation expense of $39.7 million, $36.0 million and $37.7 million, net of $7.5 million, $7.6 million and $5.6 million capitalized, respectively, related to restricted common stock.

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Restricted stock activity for the years ended December 31, 2012, 2011 and 2010 was as follows (shares in thousands):

	Number of Shares	Weighted-Average Grant Date Fair Value
Unvested restricted shares outstanding at December 31, 2009	5,322	$ 16.80
Granted(1)	6,210	$ 7.87
Vested(1)	(1,613)	$ 18.28
Forfeited / Canceled	(443)	$ 12.74
Unvested restricted shares outstanding at December 31, 2010	9,476	$ 10.89
Granted	8,003	$ 8.95
Vested	(3,270)	$ 12.91
Forfeited / Canceled	(823)	$ 9.17
Unvested restricted shares outstanding at December 31, 2011	13,386	$ 9.34
Granted	7,604	$ 7.46
Vested	(4,394)	$ 10.73
Forfeited / Canceled	(1,268)	$ 8.54
Unvested restricted shares outstanding at December 31, 2012	15,328	$ 8.07

(1) Excludes approximately 0.7 million restricted shares from stock awards assumed in the Arena Acquisition. All of these awards had vested as of December 31, 2010.

The total fair value of restricted stock that vested during the years ended December 31, 2012, 2011 and 2010, including stock awards assumed in the Arena Acquisition, was $32.1 million, $30.2 million and $17.5 million, respectively. As of December 31, 2012, there was approximately $91.0 million of unrecognized compensation cost related to unvested restricted stock awards, which is expected to be recognized over a weighted average period of 2.5 years. The Company had approximately 9.9 million shares available for grant under its existing incentive compensation plan at December 31, 2012.

Noncontrolling Interest

Noncontrolling interest represents third-party ownership interests in the Company's subsidiaries and consolidated VIEs (see Note 4), and is included as a component of equity in the accompanying consolidated balance sheets and consolidated statements of changes in equity.

18. Retirement and Deferred Compensation Plans

Retirement Plan. The Company maintains a 401(k) retirement plan for its employees. Under the plan, eligible employees may elect to defer a portion of their earnings up to the maximum allowed by regulations promulgated by the Internal Revenue Service ("IRS"). The 2012 annual 401(k) deferral limit for employees under age 50 was $17,000. Employees turning age 50 or over in 2012 could defer up to $22,500 in 2012. The Company makes matching contributions to the plan equal to 100% on the first 15% of employee deferred wages. All matching contributions are in Company stock. For 2012, 2011 and 2010, the Company satisfied its matching obligations related to employee contributions with cash purchases of Company stock. For 2012, 2011 and 2010, retirement plan expense was approximately $11.4 million, $7.4 million and $8.7 million, respectively.

Deferred Compensation Plan. Effective February 1, 2007 the Company established a non-qualified deferred compensation plan that allows eligible highly compensated employees to elect to defer income exceeding the IRS annual limitations on qualified 401(k) retirement plans. The Company makes matching contributions on non-qualified contributions up to a maximum of 15% of employee compensation. For 2012, 2011 and 2010, employer contributions were approximately $3.5 million, $3.1 million and $2.8 million, respectively.

Any assets placed in trust by the Company to fund future obligations of the Company's non-qualified deferred compensation plan are subject to the claims of creditors in the event of insolvency or bankruptcy, and participants are general creditors of the Company as to their own deferred compensation in, and the Company's contributions to, the plan.

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19. Income Taxes

The Company’s income tax benefit consisted of the following components for the years ended December 31 (in thousands):

	Year Ended December 31,		
	2012	2011	2010
Current			
Federal	$(72)	$618	$(732)
State	(2)	551	