SANDRIDGE ENERGY INC
Form 10-K
February 27, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2011

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number: 001-33784

SANDRIDGE ENERGY, INC.

(Exact name of registrant as specified in its charter)

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

(405) 429-5500

(Registrant s telephone number, including area code)

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

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

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. ¨

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 ¨
Non-accelerated filer ¨ (Do not check if smaller reporting company)	Smaller reporting company ¨

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2011 was approximately $3.9 billion based on the closing price as quoted on the New York Stock Exchange. As of February 17, 2012, there were 415,391,090 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Company s definitive proxy statement for the 2011 Annual Meeting of Stockholders are incorporated by reference in Part III.

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SANDRIDGE ENERGY, INC.

2011 ANNUAL REPORT ON FORM 10-K

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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 forward-looking statements may include projections and estimates concerning 2012 capital expenditures, the Company s liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, elements of the Company s business strategy, statements regarding the Company s pending acquisition of Dynamic Offshore Resources, LLC (Dynamic), 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, plan, goal, should, i 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 its perception of historical trends, current conditions and expected future developments as well as other factors it believes are appropriate under the circumstances. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to, or effects on the Company s business or results. The forward-looking statements in this report speak only as of the date hereof. The Company disclaims any obligation to update or revise these 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 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 to the Company s ability to drill productive, economically viable oil and natural gas wells;

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 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;

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- limitations on operations resulting from debt restrictions and financial covenants;
- potential financial losses or earnings reductions from commodity derivatives;
- potential elimination or limitation of tax incentives;
- competition in the oil and natural gas industry;
- general economic conditions, either internationally or domestically or in the jurisdictions in which 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. (including its consolidated subsidiaries and variable interest entities of which it is the primary beneficiary, the Company or SandRidge) is an independent oil and natural gas company headquartered in Oklahoma City, Oklahoma, concentrating on development and production activities related to the exploitation of its significant holdings in the Mid-Continent area of Oklahoma and Kansas and in west Texas. The Company s primary focus in the Mid-Continent area is the Mississippian formation, a shallow hydrocarbon system in northern Oklahoma and Kansas, where it had approximately 1,329,000 net acres under lease at December 31, 2011. The Company s primary area of focus in west Texas is the Permian Basin, where it had approximately 225,000 net acres under lease at December 31, 2011. The Company s oil properties in the Permian Basin include properties acquired from Forest Oil Corporation and one of its subsidiaries (collectively, Forest) in December 2009 (the Forest Acquisition) and properties owned by Arena Resources, Inc. (Arena), which was acquired by the Company in July 2010 (the Arena Acquisition). The Company also owns and operates other interests in the Mid-Continent, West Texas Overthrust (the WTO), Gulf Coast and Gulf of Mexico.

As of December 31, 2011, the Company s total estimated proved reserves were 470.6 MMBoe, of which approximately 52% were oil and approximately 49% were proved developed. As of December 31, 2011, the Company had 5,043 gross (4,266.9 net) producing wells, substantially all of which it operates, and approximately 2,695,000 gross (2,047,000 net) total acres under lease. As of December 31, 2011, the Company had 21 rigs drilling in the Mid-Continent and 15 rigs drilling in the Permian Basin.

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, 2011, the Company s drilling rig fleet consisted of 30 operational rigs. The Company also captures and 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. 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 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*.

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.

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) west Texas. Concentrating the Company s

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drilling and producing activities in these core areas allows the Company to further build and utilize its technical expertise in order to interpret specific geological and operational trends. By concentrating in these core areas, the Company is able to (i) achieve economies of scale and breadth of operations, both of which help to control costs, and (ii) opportunistically grow its holdings and operations in these areas in order to achieve production and reserve growth.

Focus on Conventional Reservoirs. The Company focuses its development efforts primarily in areas with 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 mitigate rising service costs.

Pursue Opportunistic Acquisitions. The Company occasionally reviews acquisition targets to complement its existing asset base. Accordingly, the Company selectively identifies such targets based on several factors including relative value, oil content, 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 in order 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 ensure funding for its longer term development plans and rates of return on its capital projects.

Monetize Assets. The Company periodically evaluates its properties to identify opportunities to monetize assets in order to fund or accelerate development within its areas of focus. Proceeds realized from such transactions may be used to pay down amounts outstanding under the Company s senior secured revolving credit facility (the senior credit facility), to fund its drilling program or for general corporate purposes.

2011 DEVELOPMENTS

Divestitures

Sale of Wolfberry Assets. In July 2011, the Company sold its Wolfberry assets in the Permian Basin for $151.6 million, net of fees and post-closing adjustments. The divested properties included approximately 18,000 net acres with production at the time of sale of approximately 1,600 Boe/d.

Sale of New Mexico Assets. 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. The divested properties included approximately 23,000 net acres with production at the time of sale of approximately 1,500 Boe/d.

Sale of Working Interest in Mississippian Properties. In September 2011, the Company sold to Atinum MidCon I, LLC (Atinum) a 13.2% non-operated working interest, equal to approximately 113,000 net acres, in the Mississippian formation in northern Oklahoma and southern Kansas for approximately $287.0 million, subject to post-closing adjustments. Atinum will fund a drilling carry of 13.2% of SandRidge s share of drilling and completion costs for wells drilled within an area of mutual interest up to $250.0 million, which is expected to occur over a three-year period.

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Sale of East Texas Properties. In November 2011, the Company sold its east Texas natural gas properties in Gregg, Harrison, Rusk and Panola counties for $231.0 million, subject to post-closing adjustments. The divested properties included over 23,000 net acres with production at the time of sale of approximately 4,100 Boe/d.

Royalty Trust Offerings

SandRidge Mississippian Trust I. In April 2011, SandRidge Mississippian Trust I (the Mississippian Trust I) completed its initial public offering of 17,250,000 common units representing approximately 61.6% of the beneficial interest in the Mississippian Trust I. Net proceeds to the Mississippian Trust I, after certain offering expenses, were $336.9 million. Concurrent with the closing of the offering, the Company conveyed certain royalty interests to the Mississippian Trust I in exchange for the net proceeds of the offering and 10,750,000 units, representing approximately 38.4% of the beneficial interest, in the Mississippian Trust I.

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

The Company has determined that the Mississippian Trust I is a variable interest entity (VIE) and the Company is its primary beneficiary. As such, the Company began consolidating the activities of the Mississippian Trust I into its results of operations in April 2011. See Note 3 to the Company s consolidated financial statements included in Item 8 of this report for further discussion regarding the Company s consolidation of the Mississippian Trust I.

SandRidge Permian Trust. In August 2011, SandRidge Permian Trust (the Permian Trust) completed its initial public offering of 34,500,000 common units representing approximately 65.7% of the beneficial interest in the Permian Trust. Net proceeds to the Permian Trust, after certain offering expenses, were $580.6 million. Concurrent with the closing, the Company conveyed certain royalty interests to the Permian Trust in exchange for the net proceeds of the offering and 18,000,000 units, representing approximately 34.3% of the beneficial interest in the Permian Trust.

The Company and one of its wholly owned subsidiaries entered into a development agreement with the Permian Trust that obligates the Company to drill, or cause to be drilled, a specified number of wells within an area of mutual interest, which are also subject to the royalty interest granted to the Permian Trust, within a specified period. One of the Company s wholly owned subsidiaries also granted a lien to the Permian Trust on the Company s interests in the properties where the development wells will be drilled in order to secure the estimated amount of the drilling costs for the wells.

The Company has determined that the Permian Trust is a VIE and the Company is its primary beneficiary. As such, the Company began consolidating the activities of the Permian Trust into its results of operations in August 2011. See Note 3 to the Company s consolidated financial statements included in Item 8 of this report for further discussion regarding the Company s consolidation of the Permian Trust.

Debt Transactions

Issuance of 7.5% Senior Notes. In March 2011, the Company issued $900.0 million of unsecured 7.5% Senior Notes due 2021 (the 7.5% Senior Notes) pursuant to Rule 144A and Regulation S under the Securities Act. Net proceeds from the offering were used to fund the tender offer for and the redemption of the 8.625% Senior Notes due 2015 (the 8.625% Senior Notes), discussed below. As a result of this issuance, the Company s borrowing base under its senior credit facility was reduced from $850.0 million to $790.0 million.

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Repurchase and Redemption of 8.625% Senior Notes. In March 2011, the Company purchased approximately 94.5%, or $614.2 million, of the 8.625% Senior Notes, originally issued in an aggregate principal amount of $650.0 million, through a cash tender offer. In April 2011, the Company redeemed the remaining outstanding $35.8 million aggregate principal amount of the 8.625% Senior Notes.

2012 DEVELOPMENTS

Sale of Working Interest in Mississippian Properties. In January 2012, SandRidge sold to Repsol E&P USA Inc. (Repsol) an approximate 25% non-operated working interest, equal to approximately 250,000 net acres, in the Mississippian formation in western Kansas, and an approximate 16% non-operated working interest, 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 for approximately $272.5 million. In addition, Repsol will pay for its working interest share of development costs and will fund a portion of SandRidge s development costs equal to 200% of Repsol s working interest for wells within an area of mutual interest up to $750.0 million, which is expected to occur over a five-year period.

Proposed Royalty Trust Offering. On January 5, 2012, the Company and SandRidge Mississippian Trust II (the Mississippian Trust II), a newly formed Delaware statutory trust, filed a joint registration statement with the SEC for the proposed public offering of common units representing beneficial interests in the Mississippian Trust II. In connection with the offering, the Company intends to convey certain royalty interests to the Mississippian Trust II in exchange for the net proceeds of the offering and units, representing a beneficial interest in the Mississippian Trust II. The royalty interests to be conveyed to the Mississippian Trust II are in certain existing wells and wells to be drilled on certain oil and natural gas properties leased by the Company in the Mississippian formation in northern Oklahoma and Kansas. There can be no assurance that the Company will complete this transaction, as it is subject to market conditions and other uncertainties, as well as completion of the SEC review process. If the transaction is completed, the Company intends to use the net proceeds from the offering for general corporate purposes, including to fund its 2012 capital expenditure program.

Dynamic Acquisition. On February 1, 2012, the Company entered into an agreement to acquire Dynamic, an oil and natural gas exploration, development and production company with operations in the Gulf of Mexico for approximately $1.3 billion, comprised of approximately $680.0 million in cash and approximately 74 million shares of the Company s common stock. The acquisition, which is expected to close in the second quarter of 2012, is subject to customary closing conditions, including compliance with the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act. The Company has secured $725.0 million in committed financing for the acquisition that it may use to fund the cash portion of the acquisition.

Sale of Trust Units. On February 21, 2012, the Company sold approximately 1.6 million of its Mississippian Trust I common units in a transaction exempt from registration under Rule 144 under the Securities Act for proceeds of $52.3 million.

BUSINESS SEGMENTS AND PRIMARY OPERATIONS

The Company operates in three business segments: exploration and production, drilling and oil field services and midstream gas services. Financial information regarding each segment is provided in Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations. The information below includes the activities of the Mississippian Trust I and the Permian Trust, 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 and Permian Basin. The Company operates substantially all of its wells in these areas and also operates leasehold positions in the WTO, Gulf Coast and Gulf of Mexico.

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The following table presents certain information concerning the Company s exploration and production business as of December 31, 2011, unless otherwise noted.

	Estimated Net Proved Reserves (MMBoe)	PV-10 (in millions)(1)	Daily Production (MBoe/d)(2)	Reserves/ Production (Years)(3)	Gross Acreage	Net Acreage
Area						
Mid-Continent	145.5	$ 2,265.1	19.3	20.7	1,698,222	1,332,292
Permian Basin	187.0	3,939.2	30.4	16.8	318,754	224,902
WTO	102.5	131.9	10.6	26.5	544,218	419,153
Gulf Coast	5.8	83.1	2.2	7.3	65,828	34,160
Gulf of Mexico	6.1	44.8	1.3	12.9	56,511	27,772
Other	23.7	411.8	0.8	76.1	11,326	9,139
Total	470.6	$ 6,875.9	64.6	19.9	2,694,859	2,047,418

(1) 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 Proved Reserves. The Company s total Standardized Measure was $5.2 billion at December 31, 2011.

(2) Average daily net production for the month of December 2011.

(3) Estimated net proved reserves as of December 31, 2011 divided by production for the year ended December 31, 2011.

Properties

Mid-Continent

The Company held interests in approximately 1,698,000 gross (1,332,000 net) leasehold and option acres in Oklahoma and Kansas at December 31, 2011. Associated proved reserves at December 31, 2011 totaled 145.5 MMBoe, 41% 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, 2011 included 836 gross (408.8 net) producing wells with an average working interest of 49.5%. Average daily net production from the Mid-Continent area was approximately 19.3 MBoe for the month of December 2011. The Company had 21 rigs operating in the Mid-Continent as of December 31, 2011, three of which were drilling saltwater disposal wells, and drilled 167 horizontal wells during 2011.

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. At December 31, 2011, the Company had approximately 1,692,000 gross (1,329,000 net) acres under lease, of which approximately 49,600 gross (42,000 net) acres were included in the Mississippian Trust I s area 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 formation. Since the beginning of 2009, there have been over 400 horizontal wells drilled in the Mississippian formation in northern Oklahoma and Kansas, including 205 drilled by the Company as of December 31, 2011. From December 31, 2010 to December 31, 2011, the number of the Company s producing horizontal wells in the Mississippian formation increased from 44 to 174. As of December 31, 2011, there were approximately

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43 horizontal rigs drilling in the formation, with 18 of those rigs drilling for the Company. The Company drilled a total of 167 horizontal wells in the Mississippian formation during 2011, including 48 wells subject to the Mississippian Trust I s royalty interest.

Permian Basin

The Permian Basin extends throughout southwestern Texas and southeastern New Mexico over an area approximately 250 miles wide and 300 miles long. It is one of the largest, most active and longest-producing oil basins in the United States. In 2010, production from the Permian Basin accounted for approximately 17% of total United States crude oil production, making this basin the second largest oil producing area in the continental United States after the Gulf of Mexico. The Permian Basin has been producing oil for over 80 years resulting in cumulative production of approximately 29 billion barrels.

The Company held interests in approximately 319,000 gross (225,000 net) leasehold acres in the Permian Basin at December 31, 2011, of which approximately 17,500 gross (16,000 net) acres were included in the Permian Trust s area of mutual interest. Associated proved reserves at December 31, 2011 were 187.0 MMBoe, 58% of which were proved developed reserves, based on estimates provided by independent oil and natural gas consulting firms, Netherland Sewell and Lee Keeling and Associates, Inc. (Lee Keeling). The Company s interests in the Permian Basin as of December 31, 2011 included 3,125 gross (2,976.0 net) producing wells with an average working interest of 96.2%. The Company s average daily net production was approximately 30.4 MBoe for the month of December 2011. The Company had 15 rigs operating in the Permian Basin as of December 31, 2011 and drilled 803 wells in this area during 2011, of which 195 were subject to the Permian Trust s royalty interest.

Central Basin Platform. The Company significantly expanded its holdings in the Permian Basin, specifically the Central Basin Platform (CBP) where it drilled all of its Permian Basin wells in 2011, through the Forest Acquisition in December 2009 and the Arena Acquisition in July 2010. These acquisitions added significant Permian Basin production from the Midland and Delaware Basins in Texas as well as the Northwest Shelf in New Mexico. Reserves and associated production in this area are predominantly oil. The primary reservoirs in the CBP are the dolomites and limestones of the Grayburg-San Andres and Clear Fork formations. To date, the San Andres and Clear Fork zones have produced more than 4.0 and 1.8 billion barrels of oil, respectively, with well depths typically ranging from 4,500 to 7,500 feet. The Company s properties in the CBP are positioned for infill and step-out drilling to target these reservoirs in several of the major CBP fields, such as the Fuhrman-Mascho, Goldsmith, Fullerton, Tex-Mex, Brooklaw and Robertson Fields.

West Texas Overthrust

The Company has drilled and developed natural gas in the WTO since 1986. This area is located in Pecos and Terrell counties in west Texas and is associated with the Marathon-Ouachita fold and thrust belt that extends east-northeast across the United States into the Appalachian Mountain Region. The primary reservoir rocks in the WTO range in depth from 2,000 to 17,000 feet and range in geologic age from the Permian to the Devonian. The imbricate stacking of these conventional gas-prone reservoirs provides for multi-pay exploration and development opportunities. Despite these opportunities, the WTO has historically been under-explored. The high CO_2 content of the natural gas, lack of infrastructure in the region and historical limitations of conventional subsurface geological and geophysical methods have combined to discourage exploration of the area. Additionally, low natural gas prices continue to limit activity in this area.

The Company held interests in approximately 544,000 gross (419,000 net) leasehold acres in the WTO at December 31, 2011. Associated proved reserves at December 31, 2011 were 102.5 MMBoe, 45% of which were proved developed reserves, based on estimates provided by Netherland Sewell. The Company s interests in the WTO as of December 31, 2011 included 880 gross (745.4 net) producing wells with an average working interest of 95.3%. The Company s average daily net production was approximately 10.6 MBoe for the month of December 2011.

Century Plant. In order to facilitate expansion of CO_2 treating capacity in the WTO, the Company is constructing a CO_2 treatment plant in Pecos County, Texas (the Century Plant), and associated compression and pipeline facilities pursuant to an agreement with Occidental Petroleum Corporation (Occidental). Under the terms of the agreement, Occidental will pay the Company a minimum of 100% of the contract price, or $800.0 million, plus any subsequently agreed-upon revisions, through periodic cost reimbursements based upon the percentage of the project completed by the Company. The Company expects to complete the Century Plant in two phases. Phase I is in the commissioning process with completion and transfer of title to Occidental expected in early 2012, and Phase II is under construction and expected to be completed in 2012. Upon completion of each phase of the Century Plant, Occidental will take ownership of the related assets and will operate the Century Plant for the purpose of separating and removing CO_2 from delivered natural gas. Contract losses on the construction of the Century Plant are recorded as development costs within the Company s oil and natural gas properties as part of the full cost pool, when it is determined that a loss will be incurred. Contract gains, if any, are recorded at the end of the project. As of December 31, 2011, the Company had recorded additions of $130.0 million to its oil and natural gas properties for the estimated loss identified based on current projections of the costs to be incurred in excess of contract amounts.

Pursuant to a 30-year treating agreement executed simultaneously with the construction agreement to build the Century Plant, Occidental will remove CO_2 from the Company s delivered natural gas production volumes. Under this agreement, the Company will be required to deliver certain CO_2 volumes annually once Occidental takes title of Phase I, and will have to compensate Occidental to the extent such requirements are not met. Based upon current natural gas production levels, the Company expects to accrue between approximately $17.0 million and $21.0 million during the year ending December 31, 2012 for amounts related to the Company s shortfall in meeting its delivery obligations based on the projected completion date of Phase I of the Century Plant. 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. The Company will retain all methane gas from the natural gas it delivers to the Century Plant.

Gulf Coast

As of December 31, 2011, the Company owned oil and natural gas interests in approximately 66,000 gross (34,000 net) acres in the Gulf Coast area, which encompasses the large coastal plain from the southernmost tip of Texas through the southern portion of Louisiana. As of December 31, 2011, the Company s estimated net proved reserves in the Gulf Coast area was 5.8 MMBoe with average daily net production of approximately 2.2 MBoe for the month of December 2011.

Gulf of Mexico

As of December 31, 2011, the Company owned oil and natural gas interests in approximately 57,000 gross (28,000 net) acres in state and federal waters off the coasts of Texas and Louisiana. As of December 31, 2011, the Company s estimated net proved reserves in the Gulf of Mexico was 6.1 MMBoe with average daily net production of approximately 1.3 MBoe for the month of December 2011. The Company s operations in the Gulf of Mexico extend from the coast to more than 100 miles offshore and occur in waters ranging from 30 to 1,100 feet.

Tertiary Oil Recovery

The Company currently operates three enhanced recovery projects, consisting of one active CO_2 flood and two waterfloods in which CO_2 pilot projects are currently under development. All three floods are located in the Permian Basin area of west Texas. The Wellman Unit, located in Terry County, is an active CO_2 flood in which CO_2 injection was re-initiated in November 2005. The two prospective CO_2 pilot waterfloods are the George Allen Unit and the South Mallet Unit, located in Gaines and Hockley Counties. Injection is expected to begin into the George Allen pilot in 2012 and into the South Mallet pilot in 2013. The three enhanced recovery projects had average daily net production of approximately 0.8 MBoe for the month of December 2011 and have

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produced a total of 113.4 MMBoe to date. As of December 31, 2011, net proved reserves attributable to the three projects were 23.6 MMBoe. Expansion opportunities exist in all three projects and will be evaluated based on early performance results.

Proved Reserves

The oil and natural gas reserves in this report are based on reserve reports, substantially all of which were prepared by independent petroleum engineers. The process to review and estimate the reserves begins with one of the Company s staff reservoir engineers collecting and verifying all pertinent data, including but not limited to well test data, production data, historical pricing, cost information, property ownership interests, reservoir data, geosciences data and non-confidential production data of relevant wells and operations in the area. This data was reviewed by various levels of management for accuracy, before consultation with independent petroleum engineers. Such consultation includes 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.

SandRidge s Executive Vice President Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of the Company s reserves estimates. He has a Bachelor of Science degree in Mechanical Engineering with over 30 years of practical industry experience, including over 25 years of estimating and evaluating reserve information. In addition, the Company s Executive Vice President Reservoir Engineering 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 19 full-time employees, comprised of eight degreed engineers and 11 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 observed within the reserve estimation process include:

- No employee s compensation is tied to the amount of reserves booked.

- 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.

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Each quarter, the Executive Vice President Reservoir Engineering presents the status of the Company s reserves to a committee of executives, which subsequently approves all changes. In the event the quarterly updated reserves estimates are disclosed, the aforementioned review process is evidenced by signatures from the Executive Vice President Reservoir Engineering and the Chief Financial Officer.

The Reservoir Engineering Department works closely with its independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of annually developed independent reserves estimates. These independently developed reserves estimates are adopted as the Company s corporate reserves and 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. In addition to reviewing the independently developed reserve reports, the Audit Committee annually interviews the third-party engineer at Netherland Sewell who is primarily responsible for the reserve report. The Audit Committee also periodically interviews the other independent petroleum consultants used to prepare estimates of proved reserves.

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

	December 31,		
	2011	**2010**	**2009**
Netherland, Sewell & Associates, Inc.	80.5%	71.9%	51.7%
Lee Keeling and Associates, Inc.	15.6%	20.3%	33.7%
DeGolyer and MacNaughton		4.3%	9.6%
Total	96.1%	96.5%	95.0%

The remaining 3.9%, 3.5% and 5.0% of the Company s estimated proved reserves as of December 31, 2011, 2010 and 2009, 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 and natural gas reserves as of December 31, 2011 are filed with this report as Exhibits 99.1 99.2. The geographic location of the Company s estimated proved reserves prepared by each of the independent petroleum consultants as of December 31, 2011 is presented below.

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

The qualifications of the technical person 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.

more than 30 years of practical experience in petroleum engineering and almost 15 years estimating and evaluating reserve information;

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a registered professional engineer in the states of Texas, Louisiana and Wyoming; and

a Bachelor of Science Degree in Civil Engineering and Masters in Business Administration.

Lee Keeling and Associates, Inc.

57 years of practical experience in petroleum engineering and more than 48 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.

The following estimates of proved oil and natural gas reserves are based on reserve reports as of December 31, 2011, 2010 and 2009, substantially all of which were prepared by independent petroleum engineers. The estimates include reserves attributable to the Mississippian Trust I and the Permian Trust, 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, 2011, 2010 and 2009, using first-day-of-the-month prices for each month. The Company estimates that approximately 73% of its current proved undeveloped reserves will be developed by 2013 and all of its current proved undeveloped reserves will be developed by 2014. See Critical Accounting Policies and Estimates in Item 7 of this report for further discussion of uncertainties inherent to the reserves estimates. See Note 25 in Item 8 of this report for reserve and standardized measure of discounted net cash flows amounts attributable to noncontrolling interests.

		December 31,	
	2011	**2010**	**2009**
Estimated Proved Reserves(1)			
Developed			
Oil (MMBbls)	118.7	92.0	38.3
Natural gas (Bcf)(2)	670.4	784.3	592.8
Total proved developed (MMBoe)	230.4	222.7	137.1
Undeveloped			
Oil (MMBbls)	126.1	160.1	67.0
Natural gas (Bcf)(2)	684.7	978.4	87.3
Total proved undeveloped (MMBoe)	240.2	323.2	81.6
Total Proved			
Oil (MMBbls)	244.8	252.1	105.3
Natural gas (Bcf)(2)	1,355.1	1,762.7	680.1

Total proved (MMBoe)(3)	470.6	545.9	218.7
PV-10 (in millions)(4)	$ 6,875.9	$ 4,509.2	$ 1,561.0
Standardized Measure of Discounted Net Cash Flows (in millions)(3)(5)	$ 5,216.3	$ 3,683.5	$ 1,561.0

(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

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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.

	Weighted average wellhead prices		Index prices	
	Oil (per Bbl)	Natural gas (per Mcf)	Oil (per Bbl)	Natural gas (per Mcf)
December 31, 2011	$ 85.77	$ 4.06	$ 92.71	$ 4.12
December 31, 2010	$ 66.93	$ 3.80	$ 75.96	$ 4.38
December 31, 2009	$ 49.98	$ 3.41	$ 57.65	$ 3.87

(2) 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.

(3) At December 31, 2011, estimated total proved reserves and Standardized Measure attributable to noncontrolling interests were approximately 26.3 MMBoe and approximately $932.8 million, respectively. There were no proved reserves or Standardized Measure attributable to noncontrolling interest at December 31, 2010 or 2009.

(4) 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, 2011, 2010 and 2009. PV-10 differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. Due to the full valuation allowance on the Company s net deferred tax asset at December 31, 2009 that reduced to zero a tax benefit that otherwise would result from the tax effects of PV-10, there was no effect of income taxes on Standardized Measure at December 31, 2009. 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 are not dependent on the taxpaying status of the entity. The following table provides a reconciliation of the Company s Standardized Measure to PV-10:

	2011	December 31, 2010 (In millions)	2009
Standardized Measure of Discounted Net Cash Flows	$ 5,216.3	$ 3,683.5	$ 1,561.0
Present value of future income tax discounted at 10%	1,659.6	825.7	
PV-10	$ 6,875.9	$ 4,509.2	$ 1,561.0

(5) 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. Due to the full valuation allowance on the Company s net deferred tax asset at December 31, 2009 that reduced to zero a tax benefit that otherwise would result from the tax effects of PV-10, there was no effect of income taxes on Standardized Measure at December 31, 2009.

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 from known reservoirs from a given date forward, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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 term reasonable certainty implies a high degree of confidence that the quantities of oil and/or natural gas actually

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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.

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, which comprises a significant portion of the additions to the Company s proved reserves. 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 and 178 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 in situ fluids 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. While vertical well control exists across all of the development area most of the existing producing horizontal wells were drilled without benefit of a direct offset producing lateral section. These wells all encountered proven reserves in the Mississippian formation. The proved undeveloped locations within the development area are generally direct parallel offsets to the horizontal wells drilled and producing to date.

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Proved Undeveloped Reserves. During 2011, the Company drilled 855 wells and approximately $817.0 million of its drilling capital expenditures were used to convert approximately 50.3 MMBoe of proved undeveloped reserves to proved developed reserves. At December 31, 2011, 763 of these wells were classified as proved developed producing properties with the remaining wells still in progress. During 2010, the Company drilled 424 wells and approximately $480.7 million of its drilling capital expenditures were used to convert approximately 37.4 MMBoe of proved undeveloped reserves to proved developed reserves. At December 31, 2010, 392 of these wells were classified as proved developed producing properties with the remaining wells still in progress. During 2009, the Company drilled 104 wells and approximately $128.6 million of its drilling capital expenditures were used to convert approximately 8.7 MMBoe of proved undeveloped reserves to proved developed reserves. At December 31, 2009, 92 of these wells were classified as proved developed producing properties with the remaining wells still in progress.

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. For additional information, see Note 25 to the Company s consolidated financial statements in Item 8 of this report.

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.

The 12-month average natural gas index price of $3.87 per Mcf used in the estimation of reserves as of December 31, 2009 resulted in downward revisions of quantities associated with the Company s proved undeveloped properties as a significant number of properties generated no PV-10 value resulting in the elimination of associated reserve quantities and a shortening of the productive lives of certain proved properties that became uneconomic earlier in their lives with the use of lower natural gas prices compared to prices used in the estimation of reserves in previous periods.

Fields. Three fields, the Mississippi Lime Horizontal, the Fuhrman-Mascho and the Piñon, each contained more than 15% of the Company s total proved reserves at December 31, 2011. 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 has estimated proved oil and natural gas reserves in the Mississippi Lime Horizontal Field of 128 MMBoe as of December 31, 2011. The Company s interests in the Mississippi Lime Horizontal Field as of December 31, 2011 included 200 gross (147.9 net) producing wells and a 73.9% 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 Fuhrman-Mascho Field is the fifth largest producing field in the Permian Basin and has produced approximately 142 MMBoe since its discovery in 1930. The Company has estimated proved oil and natural gas reserves in the Fuhrman-Mascho Field of 89 MMBoe as of December 31, 2011. The Company s interests in the Fuhrman-Mascho Field as of December 31, 2011 included 1,761 gross (1,709.9 net) producing wells and a 97.1% average working interest in the producing area.

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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). As of December 31, 2011, the Company s estimated proved oil and natural gas reserves in the Piñon Field were 102.4 MMBoe. The Company s interests in the Piñon Field as of December 31, 2011 included 870 gross (738.1 net) producing wells and a 95.6% average working interest in the producing area.

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.

	2011		
	Oil (MBbls)	**Natural Gas (Bcf)**	**Total (MBoe)**
Field			
Mississippi Lime Horizontal	1,209.5	8.3	2,598.2
Fuhrman-Mascho	3,768.5	1.6	4,040.7
Piñon	41.0	28.2	4,748.7

	2010		
	Oil (MBbls)	**Natural Gas (Bcf)**	**Total (MBoe)**
Fuhrman-Mascho(1)	1,468.4	0.7	1,587.3
Piñon	60.8	40.3	6,779.9

	2009		
	Oil (MBbls)	**Natural Gas (Bcf)**	**Total (MBoe)**
Piñon	108.1	52.2	8,812.8

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

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,		
	2011	**2010**	**2009**
Production Data			
Oil (MBbls)(1)	11,830	7,386	2,894
Natural gas (MMcf)	69,306	76,226	87,461
Total volumes (MBoe)	23,381	20,090	17,471
Average daily total volumes (MBoe/d)	64.1	55.0	47.9

Year Ended December 31,

	2011	2010	2009
Average Prices(2)			
Oil (per Bbl)(1)	$ 83.21	$ 66.89	$ 55.62
Natural gas (per Mcf)	$ 3.50	$ 3.68	$ 3.36
Total (per Boe)	$ 52.47	$ 38.56	$ 26.03

(1) Includes natural gas liquids.

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

	Year Ended December 31,		
	2011	2010	2009
Expenses per Boe			
Lease operating expenses			
Transportation	$ 0.71	$ 0.60	$ 0.66
Processing, treating and gathering(1)	1.59	1.92	2.17
Other lease operating expenses	10.73	8.54	6.29
Total lease operating expenses	$ 13.03	$ 11.06	$ 9.12
Production taxes(2)	$ 1.97	$ 1.45	$ 0.23
Ad valorem taxes	$ 0.78	$ 0.78	$ 0.60

(1) Includes costs attributable to gas treatment to remove CO_2 and other impurities from natural gas.
(2) Net of severance tax refunds.

Productive Wells

The following table sets forth the number of productive wells in which the Company owned a working interest at December 31, 2011. 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 an 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	291	187.1	545	221.8	836	408.8
Permian Basin	2,964	2,849.6	161	126.4	3,125	2,976.0
WTO	18	17.1	862	728.3	880	745.4
Gulf Coast	20	9.7	99	63.8	119	73.6
Gulf of Mexico	25	15.0	11	7.2	36	22.2
Other	47	40.9			47	40.9
Total	3,365	3,119.4	1,678	1,147.5	5,043	4,266.9

Developed and Undeveloped Acreage

The following table sets forth information regarding the Company s developed and undeveloped acreage at December 31, 2011:

	Developed Acreage		Undeveloped Acreage	
	Gross	Net	Gross	Net
Area				
Mid-Continent	261,635	165,512	1,436,587	1,166,780
Permian Basin	133,276	109,136	185,478	115,766
WTO	36,569	33,969	507,649	385,184
Gulf Coast	50,936	29,761	14,892	4,399

Gulf of Mexico	56,511	27,772		
Other	10,966	8,940	360	199
Total	549,893	375,090	2,144,966	1,672,328

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, 2011 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, 2012	340,929	208,368
December 31, 2013	747,801	603,372
December 31, 2014	769,542	635,004
December 31, 2015 and later	182,478	153,685
Other(1)	104,216	71,899
Total	2,144,966	1,672,328

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

Included in the acreage expiring during the twelve months ending December 31, 2012 above are approximately 278,000 gross (174,000 net) acres in the WTO. The development of this acreage is largely dependent on natural gas prices during this period.

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 refer to gross wells multiplied by the Company s weighted average working interest. As of December 31, 2011, the Company had 116 gross (104.5 net) operated wells drilling, completing or awaiting completion.

	2011				2010				2009			
	Gross	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**	**Gross**	**Percent**	**Net**	**Percent**
Completed Wells												
Development												
Productive	895	99.7%	850.0	99.7%	579	95.7%	538.8	95.7%	147	97.4%	117.2	97.9%
Dry	3	0.3%	2.9	0.3%	26	4.3%	24.3	4.3%	4	2.6%	2.5	2.1%
Total	898	100.0%	852.9	100.0%	605	100.0%	563.1	100.0%	151	100.0%	119.7	100.0%
Exploratory												
Productive	38	100.0%	33.7	100.0%	15	83.3%	14.9	83.2%	9	100.0%	8.6	100.0%
Dry		0.0%		0.0%	3	16.7%	3.0	16.8%				
Total	38	100.0%	33.7	100.0%	18	100.0%	17.9	100.0%	9	100.0%	8.6	100.0%
Total												
Productive	933	99.7%	883.7	99.7%	594	95.3%	553.7	95.3%	156	97.5%	125.8	98.1%
Dry	3	0.3%	2.9	0.3%	29	4.7%	27.3	4.7%	4	2.5%	2.5	1.9%
	936	100.0%	886.6	100.0%	623	100.0%	581.0	100.0%	160	100.0%	128.3	100.0%

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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, 2011.

	Owned	Third-Party	Total
Mid-Continent	8	13	21
Permian Basin	12	3	15
Total	20	16	36

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 two customers that individually accounted for more than 10% of its total revenue during 2011. See Note 23 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 commitments to deliver fixed and determinable quantities of oil and natural gas in the future under existing sales contracts or agreements.

Title to Properties

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

Capital Expenditures

The Company s capital expenditures for 2011 related to its exploration and production segment were $1.7 billion, including amounts spent to develop wells in the Mississippian Trust I and the Permian Trust areas of mutual interest. The Company has budgeted approximately $1.5 billion in capital expenditures, excluding acquisitions and capital expenditures associated with properties to be acquired from Dynamic, in 2012 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 primarily in west Texas, northwestern Oklahoma and Kansas 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, 2011, the Company s drilling rig fleet consisted of 30 operational rigs with 20 of these rigs working on Company-owned properties in the Mid-Continent and Permian Basin.

Types of Drilling Contracts

The Company obtains its contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with customers. The Company s drilling contracts generally provide for compensation on a daywork or footage basis. The contract terms the Company offers 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. For a discussion of these contracts, see Management s Discussion and Analysis of Financial Condition and Results of Operations Segment Overview Drilling and Oil Field Services Segment in Item 7 of this report.

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 2011, the Company performed approximately 74% of its drilling and oil field services in support of its exploration and production business. For the years ended December 31, 2011, 2010 and 2009, the Company generated revenues of $103.3 million, $28.6 million and $23.6 million, respectively, for drilling and oil field services performed for third parties.

Capital Expenditures

The Company s capital expenditures for 2011 related to its drilling and oil field services were $25.7 million. The Company has budgeted approximately $20.0 million in capital expenditures in 2012 for its drilling and oil field services segment.

Midstream Gas Services

The Company 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. The following tables set forth information regarding the Company s primary midstream assets as of December 31, 2011:

	Plant Capacity (MMcf/d)(1)	Average Utilization(2)	Third-Party Usage
Gas Treating Plants			
Pike s Peak	85	25%	<1%
Grey Ranch	220	26%	6%

(1) Based on a 69% CO_2 natural gas stream.
(2) Average utilization for the year ended December 31, 2011.

	CO_2 Compression Capacity (MMcf/d)	Average Utilization(1)
SandRidge CO_2 Compression Facilities		

Pike s Peak	36.0	29%
Mitchell	26.5	28%
Grey Ranch	64.0	20%
Terrell	28.0	73%

(1) Average utilization for the year ended December 31, 2011.

West Texas

The Company owns and operates the Pike s Peak gas treating plant in Pecos County, Texas, which has the capacity to treat 85 MMcf per day of natural gas for the removal of CO_2 from production in the Piñon Field and nearby areas. The Company also owns the Grey Ranch gas treating plant located in Pecos County and has a 50% interest in the partnership that leases the plant from the Company under a lease expiring in 2020. The treating capacity for both the Pike s Peak and Grey Ranch plants is dependent upon the quality of natural gas being treated.

The Company s two west Texas gas treating plants remove CO_2 from natural gas production and deliver residue gas into the Atmos Lone Star and Enterprise Energy Services pipelines. These pipelines are operated on fixed fees based upon throughput of natural gas. In addition, the Company has access of up to 30 MMcf per day of treating capacity at Hoover Energy Partners Mitchell Plant under a long-term fixed fee arrangement.

The Company also owns or operates over 1,700 miles of gas gathering pipelines and numerous dehydration units. Within the Piñon Field, the Company operates separate gathering systems for sweet natural gas and produced natural gas containing high percentages of CO_2. In addition to servicing the Company s exploration and production business, these assets also service other oil and natural gas companies.

The majority of the produced natural gas gathered by the Company s midstream assets in west Texas requires compression from the wellhead to the final sales meter. As of December 31, 2011, the Company owned or operated approximately 75,000 horsepower of gas compression in west Texas.

The Century Plant, in Pecos County, Texas, will add 400 MMcf per day in available treating capacity when fully commissioned. During 2011, the Company continued with the operational assessment phase of the Century Plant, including diverting some of the Company s natural gas from the Company s existing gas treating plants and CO_2 compression facilities and processing it at the Century Plant. As a result of the assessments, the Century Plant has been taken off line from time to time to resolve certain operational issues. The Company is currently in the process of diverting its high CO_2 natural gas production to the Century Plant and commencing performance testing for Phase I. Upon successful completion of the performance testing, the use of the Company s existing gas treating plants and CO_2 compression facilities in west Texas may be limited. The extent of such limitation will depend on a variety of factors, including natural gas prices and the expected need for such plants and facilities to supplement treating capacity at the Century Plant going forward. During the second quarter of 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 the second half of 2011. As of December 31, 2011, no impairment of these plants or facilities was deemed necessary.

In conjunction with the June 2009 sale of the Company s gathering and compression assets located in the Piñon Field, the Company entered into a gas gathering agreement and an operations and maintenance agreement with Piñon Gathering Company, LLC. 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 that was negotiated at arms length for such services. See Note 16 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.

Other Areas

As of December 31, 2011, the Company owned approximately 50 miles of pipeline in the Mid-Continent area and owned approximately 54 miles of pipeline gathering systems and operated over 2,500 horsepower of gas compression in the Gulf Coast area.

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 2011, the Company spent $93.1 million in capital expenditures to install pipeline and compression infrastructure and for other general corporate purposes. The Company has budgeted approximately $135.0 million in 2012 capital expenditures for its midstream gas services segment and other general corporate purposes.

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 with 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 50,000 MMBtu per day of firm transportation service subscribed on the Oasis Pipeline for a portion of its Piñon Field production for 2012, 75,000 MMBtu per day on the Mid-Continent Express Pipeline through August 2014 and 50,000 MMBtu per day on Mid-Continent Express Pipeline through August 2019.

Customers

During 2011, the Company performed approximately 65% of its midstream services in support of its exploration and production business. For the years ended December 31, 2011, 2010 and 2009, the Company generated revenues of $65.2 million, $98.5 million and $83.9 million, respectively, from midstream services performed for third parties.

Other Operations

The Company s CO_2 capturing operations are conducted through SandRidge CO_2. As of December 31, 2011, SandRidge CO_2 owned 240 miles of CO_2 pipelines in west Texas with approximately 56,000 horsepower of owned and leased CO_2 compression available and currently operational. The captured CO_2 is primarily used for tertiary oil recovery operations.

COMPETITION

The Company believes that its leasehold acreage position, drilling and oil field services businesses, midstream assets, CO_2 supply and technical and operational capabilities generally enable the Company to compete effectively. The Company believes its geographic concentration of operations and vertical integration enables 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 attempt to maintain cash flow. Certain

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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 market prices. The Company s larger or fully integrated competitors may be able to absorb the burden of any existing and 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 the Company competes for are usually awarded on the basis of competitive bids. The Company may, based on the economic environment at the time, determine that market conditions and profit margins are such that contract drilling for third parties is not a beneficial use of its resources.

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

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

SEASONAL NATURE OF BUSINESS

Generally, demand for oil and natural gas decreases during the summer months and increases during the winter months. Certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit the Company s drilling and producing activities and other oil and natural gas operations in a portion of its operating areas. These seasonal anomalies can pose challenges for meeting the Company s well drilling objectives and can increase competition for equipment, supplies and personnel during the spring and summer months, 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 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 have made and expect 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,

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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 they 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 many of the other wastes associated with the exploration, production and 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 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 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, 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. In July 2011, the EPA proposed a range of new regulations that would establish new air emission controls for oil and natural gas production and natural gas processing, including, among other things, a new source performance standard for volatile organic compounds that would apply to newly hydraulically fractured wells, existing wells that are re-fractured, compressors, pneumatic controllers, condensate and crude oil storage tanks and natural gas processing plants. The EPA is under a court order to finalize these proposed regulations by April 3, 2012.

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 the Clean Water Act and analogous state laws, permits must be obtained to discharge produced waters and sand, drilling fluids, drill cuttings and other substances related to the oil and 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 EPA or the analogous state agency. 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 in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

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Climate Change

In December 2009, the EPA published its findings that emissions of carbon dioxide, 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. The EPA s rules relating to emissions of GHGs from stationary sources of emissions are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. In addition, the EPA has adopted rules requiring the reporting of GHG emissions from onshore oil and natural gas production facilities in the United States on an annual basis. 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, some scientists have concluded that 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. If any such effects were to occur, they could have a material adverse effect on the Company and potentially subject the Company to further regulation.

In addition, Congress has considered legislation to reduce emissions of GHGs and almost one-half of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the planned development 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 next six years, through 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.

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 hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in the Company s operations and that this information be provided to employees, state and local government authorities and citizens. The Company believes that it is in substantial compliance with all applicable laws and regulations relating to worker health and safety.

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State Regulation

The states in which the Company operates regulate 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. The effect of these regulations may be to limit the number of wells that the Company may drill, impact the locations at which the Company may drill wells, restrict the amounts of oil and natural gas that may be produced from the Company s wells and increase the costs of the Company s operations.

Hydraulic Fracturing

Oil and natural gas may be recovered from certain of the Company s oil and natural gas properties through the use of hydraulic fracturing, combined with sophisticated drilling. Hydraulic fracturing, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices, (*i.e.*, use of diesel, kerosene and similar compounds in the fracturing fluid). 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. The U.S. Department of the Interior is considering disclosure requirements and other mandates for hydraulic fracturing on federal lands. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Certain states in which the Company operates, including Texas 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 December 2011, the Railroad Commission of Texas finalized regulations 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 the state level, such legal requirements could cause project delays and make it more difficult or costly for the Company to perform fracturing to stimulate production of oil and natural gas. These delays or additional costs could adversely affect the determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at 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 and potential increases in costs. 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, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. In addition, the U.S. Department of Energy has conducted an investigation of practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods and the U.S. Government Accountability Office has investigated how hydraulic fracturing might adversely affect water resources. Additionally, certain members of Congress have called upon 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. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

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

OTHER REGULATION OF THE OIL AND NATURAL GAS INDUSTRY

The oil and natural gas industry is extensively regulated by numerous federal, state and local 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 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.

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. Effective October 1, 2011, the Bureau of Ocean Energy Management, Regulation and Enforcement (the BOEMRE), 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 (the BSEE) and the Bureau of Energy Management (the BOEM). The BSEE is responsible for the safety and enforcement functions of offshore oil and 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, review and administration of oil and gas exploration and development plans. 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. BSEE requires federal leaseholders to post performance bonds or otherwise provide necessary financial assurances to provide for such abandonment, decommissioning and removal. The Oil Conservation Division of the New Mexico Energy, Minerals and Natural Resources Department requires the posting of performance bonds to fulfill financial requirements for owners and operators on state land. The Railroad Commission of Texas has financial responsibility requirements for owners and operators of facilities in state waters to provide for similar assurances. 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. Although the ACOE does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

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 complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of the Company s sales of its own production. Under the Energy Policy Act of 2005, FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

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

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

EMPLOYEES

As of December 31, 2011, the Company had 2,432 full-time employees, including more than 298 geologists, geophysicists, petroleum engineers, technicians, land and regulatory professionals. Of the Company s 2,432 employees, 667 are located at the Company s headquarters in Oklahoma City, Oklahoma, and the remaining employees work in the Company s various field offices and drilling sites.

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

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

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

Bcf. Billion cubic feet of natural gas.

Bcfe. Billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

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 2011 of $4.12/Mcf for natural gas and $92.71/Bbl for oil, the ratio of economic value of oil to gas was approximately 22 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.

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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. Developed oil and natural gas reserves are 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 leases, flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

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

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

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

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

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

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geological barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or

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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.

Mcfe. Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

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.

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

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

Production costs.

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

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

(B) Repairs and maintenance.

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

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

(E) Severance taxes.

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

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

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

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

Proved oil 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.

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 blow out 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.

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 or tornadoes;

- reductions in oil and natural gas prices;
- oil and natural gas property title problems; 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.

Oil and natural gas prices fluctuate due to a number of factors that are beyond the control of the Company, 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 realized 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, 2008 through December 31, 2011, the highest monthly NYMEX settled price was $140.00 per Bbl and the lowest was $41.68 per Bbl. For natural gas, from January 1, 2008 through December 31, 2011, the highest monthly NYMEX settled price was $13.11 per MMBtu and the lowest was $2.84 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 the Company can produce economically and, therefore, could have a material adverse effect on the Company s 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 year ended December 31, 2011 or 2010, while its ceiling limitations during 2009 resulted in non-cash impairment charges totaling $1,693.3 million. 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.

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

As of December 31, 2011, the Company s total indebtedness was $2.8 billion, and it had preferred stock outstanding with an aggregate liquidation preference of $765.0 million. The Company s substantial level of indebtedness and the dividends payable on its preferred stock outstanding 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 its 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 multiple 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. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this report. See Business The Company s Businesses 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 most likely will vary 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 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 its 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 regulations 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 its 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 the Company s 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.

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 us 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 2011, the Company completed a total of 936 gross wells, of which 3 were identified as dry wells. If the Company drills additional wells that it identifies as dry wells in its current and future prospects, the Company s 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 pipelines and other transportation facilities.

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

Volatility in the capital markets could affect the Company s ability to obtain capital, cause the Company 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 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 the Company s 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 inherently incomplete because an in-depth review of every individual property involved in each acquisition generally is not feasible. Even a

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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 the Company s 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 it currently anticipates.

As of December 31, 2011, 51% 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 its 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 west Texas, making it vulnerable to risks associated with operating in a limited number of major geographic areas.

As of December 31, 2011, approximately 71% of the Company s proved reserves and approximately 66% of its annual production were located in the Mid-Continent and Permian Basin. This concentration could disproportionately expose the Company to operational and regulatory risk in these areas. This relative lack of diversification in location of the Company s key operations could expose it 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 its properties were more diversified.

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, debt 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 current and new 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, operating difficulties, declines in reserves or for any other reason, it 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

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financing. However, the Company s senior credit facility contains covenants limiting its ability to incur additional indebtedness, which its lenders may withhold in their sole discretion. The Company s senior note indentures also contain covenants that may restrict its 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 it 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 obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. The Company also is required 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 its operations and events or circumstances beyond its control. If commodity prices decline, this could adversely affect the Company s ability to meet 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 financing 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 is 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 it 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 is 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, its assets may not be sufficient to repay such indebtedness in full.

The Company s derivative activities could result in financial losses and could reduce its earnings.

To achieve a more predictable cash flow and to reduce the Company s exposure to adverse fluctuations in the prices of oil and natural gas, the Company currently has, and may in the future, enter into derivative contracts for a portion of its oil and natural gas production, including fixed price swaps, collars and basis swaps. The Company has not 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 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.

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

All of the Company s consolidated drilling and services revenues are derived from 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.

A significant or prolonged decrease in natural gas production in the Company s areas of operations, due to declines in production from existing wells, depressed commodity prices or otherwise, would adversely affect its ability to satisfy certain contractual obligations and revenues and cash flow from the Company s midstream gas services segment.

In June 2009, the Company sold an entity, Piñon Gathering Company, LLC (PGC), holding its gathering and compression assets located in the Piñon Field, which is part of the WTO in Pecos County, Texas, to an unaffiliated third party. In conjunction with the sale, the Company entered into a gas gathering agreement pursuant to which it dedicated its Piñon Field acreage to PGC for gathering services for 20 years. During that period, the Company has minimum throughput and delivery obligations to PGC. In addition, the Company continues to construct gathering and compression assets in the Piñon Field. Most of the reserves supporting the Company s contractual obligations to PGC and its own midstream assets are operated by the Company s exploration and production segment. A material decrease in natural gas production in the Company s areas of operation would result in a decline in the volume of natural gas delivered to PGC and the Company s pipelines and facilities for gathering, transporting and treating. The Company has no control over many factors affecting production activity, including prevailing and projected energy prices, demand for hydrocarbons, the level of reserves, geological considerations, governmental regulation and the availability and cost of capital. The Company is obligated to pay minimum fees under the gas gathering agreement with PGC if it does not satisfy the contractual throughput and delivery commitments to PGC, due, for example, to the Company s failure to connect new wells to PGC s gathering systems or when there is a decline in the amount of natural gas that the Company produces from the Piñon Field. See Note 16 in Item 8 of this report for contractual amounts due under this agreement. In addition, if the Company fails to connect new wells to its own 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.

Many of the Company s prospects in the WTO may contain natural gas that is high in CO_2 content, which can negatively affect the Company s 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

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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 will not know the amount of CO_2 that it will encounter in any well until it is drilled. As a result, sometimes the Company encounters CO_2 levels in its wells that are higher than expected. Since the treatment expenses are incurred on a 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. Historically the Company s plant shrink has been approximately 6% in the WTO. After giving effect to plant shrink, as many as 3.5 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.

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 the Company s 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, it 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.

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

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experiences any of these problems, its ability to conduct operations could be adversely affected. While the Company maintains insurance coverage it deems appropriate for these risks, the Company s 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.

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

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 its production. 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. For example, in 2009 the Company experienced capacity limitations on high CO_2 gas treating in the Piñon Field. The Company s failure to obtain such services on acceptable terms in the future or expand the Company s 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 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 the Company can, which would adversely affect the Company s competitive position. The Company s ability to acquire additional properties and to discover reserves in the future will be dependent 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, the Company may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties. See Business Competition in Item 1 of this report.

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 cost to construct the Century Plant may exceed estimated costs, and the Company may not be able to satisfy its CO_2 volume delivery requirements.

The Company is constructing the Century Plant, a CO_2 treatment plant in Pecos County, Texas, and associated compression and pipeline facilities pursuant to an agreement with a subsidiary of Occidental. The Century Plant will be owned and operated by Occidental for the purpose of separating and removing CO_2 from natural gas delivered by the Company. The cost to construct the Century Plant may exceed current estimated costs, which exceeded the contract amount by approximately $130.0 million as of December 31, 2011. Pursuant to a 30-year treating agreement executed simultaneously with the construction agreement, Occidental will remove CO_2 from the Company s delivered production volumes, with the Company required to deliver certain minimum volumes annually and compensate Occidental to the extent such requirements are not met. The Company may not be able to find, produce and deliver enough high CO_2 gas to meet its delivery obligations. As of December 31, 2011, the Company expects to accrue between approximately $17.0 million and $21.0 million during the year ending December 31, 2012 for amounts related to the Company s shortfall in meeting its natural gas delivery obligations. In addition, there are significant risks associated with the operation and performance of a facility such as the Century Plant with no guarantee that the Century Plant will operate at its designed capacity or otherwise perform as anticipated.

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 existing 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 has 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 have a material adverse effect on its 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 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 ability to restructure the Company s 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 require increased capital costs on the part of 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 it conducts its business, which could have a material adverse effect on the Company s financial condition, results of operations and cash flows and which could reduce cash received by or available for distribution, including any amounts paid by the Company for transportation on downstream interstate pipelines.

The Company s operations are subject to environmental laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations or result in significant costs and liabilities.

The Company s oil and natural gas exploration and production operations are subject to stringent and comprehensive federal, state, tribal, regional 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 the Company s 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; impose 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 and whether its 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 the Company s 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. 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 the Company to incur significant expenditures 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 the increased cost of compliance, the Company may decide to discontinue drilling.

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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 the Company s 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 its 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.

In recent years, the Obama administration s budget proposals and other proposed legislation have included the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. These changes 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 U.S. 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 such changes will be enacted or how soon any such changes would become effective. The passage of any legislation as a result of these 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 creates 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-

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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 establishes 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. While the Company may qualify for one or more of such exceptions, the scope of these exceptions is uncertain and will be further defined through rulemaking proceedings at the CFTC and SEC. Further, 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 new legislation, which may increase the Company s transaction costs or make it more difficult for it 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 shall be required 60 days after the CFTC completes certain definitional rulemaking, which is expected to occur later in 2012. Therefore, it is not possible at this time to predict the consequences that will arise from the new position limits regime. Regulations that subject the Company or its derivatives counterparties to limits on commodity positions could have an adverse effect on the Company s ability to hedge risks associated with its business or on the cost of its hedging activity.

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. The process is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices. 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. Certain states in which the Company operates, including Texas 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 December 2011, the Railroad Commission of Texas finalized regulations 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, such legal requirements could cause project delays and make it more difficult or costly for the Company to perform fracturing to stimulate production from a formation. 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, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United

States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA announced on October 20, 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. In addition, the U.S. Department of Energy is conducting an investigation of practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands. Additionally, 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. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

Climate change laws and regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil and natural gas that the Company produces while the physical effects of climate change could disrupt its 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. These findings allow the agency 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 rules relating to emissions of GHGs from stationary sources of emissions are currently subject to a number of political and legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. In addition, the EPA has adopted rules requiring the reporting of GHG emissions from onshore oil and natural gas production facilities in the United States on an annual basis. Both houses of Congress have from time to time considered legislation to reduce emissions of GHGs and almost one-half of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs. 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, some scientists have concluded that 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, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on the Company s assets and operations.

Risks Related to the Company s Acquisition of Dynamic Offshore Resources, LLC

If the Company completes its pending acquisition of Dynamic, its business and prospects will be subject to additional risks relating to Dynamic s offshore operations in the Gulf of Mexico, and risks relating to offshore operations generally may become more significant to the operation of the Company s business as a whole.

The Company may not realize the anticipated benefits of its pending acquisition of Dynamic or other future acquisitions, and integration of acquisitions may disrupt the Company s business and management.

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The Company s acquisition of Dynamic is pending and the Company 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 the Dynamic acquisition 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 controls over financial reporting are effective; and
- potential incompatibility of business cultures.

If the Company completes the Dynamic acquisition, Dynamic s offshore operations will 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. As a result, if the Company completes the Dynamic acquisition, it could incur substantial liabilities that could reduce or eliminate the funds available for exploration, development or leasehold acquisitions or result in loss of equipment and properties.

In addition, if the Company completes the Dynamic acquisition, 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, which costs and damages could be material to its business, financial condition or results of operations.

If the Company completes the Dynamic acquisition, reserves associated with Gulf of Mexico properties would 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.

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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, if the Company completes the Dynamic acquisition, its 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 revenues and return on capital for Gulf of Mexico properties will depend on prices prevailing during these relatively short production periods.

If the Company completes the Dynamic acquisition, its 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 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 from the BOEMRE. If the Company completes the Dynamic acquisition, it will be required to interact with both BOEM and BSEE to obtain approval of exploration and development plans and issuance of drilling permits for Dynamic s properties, which may result in added plan approval or drilling permit delays. While legislation has been introduced in the U.S. Congress to expedite the process for obtaining offshore permits that include limitations on the timeframe for environmental and judicial review, there is no guarantee that this or similar legislation will pass.

In addition to the drilling restrictions, new safety measures and permitting requirements issued by the BOEMRE, 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 if it completes the Dynamic acquisition. 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.

If the Company completes the Dynamic acquisition, 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 oil spill response requirements.

- The Compliance and Review NTL, which imposes requirements for operators to secure independent reviews of well design, construction and flow intervention processes, 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.

On September 14, 2011, BOEMRE proposed rules that would amend the Workplace Safety Rule by requiring the imposition of certain added safety procedures to a company s SEMS not covered by the original rule and revising existing obligations that a company s SEMS be audited by requiring the use of an independent third party auditor who has been pre-approved by the agency to perform the auditing task.

As a result of the issuance of these new regulatory requirements, the BSEE has been taking much longer than in the past to review and approve permits for drilling operations. If the Company completes the Dynamic acquisition, it 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. Consequently, if the Company completes the Dynamic acquisition, the Company may become subject to a variety of unforeseen adverse consequences arising directly or indirectly from the Deepwater Horizon incident.

If the Company completes the Dynamic acquisition, new regulatory requirements could significantly impact the Company s estimates of future asset retirement obligations from period to period.

If the Company completes the Dynamic acquisition, it will be responsible for plugging and abandoning wellbores and decommissioning associated platforms, pipelines and facilities on Dynamic s oil and natural gas properties. In addition to the NTLs discussed previously, the BOEMRE issued an NTL that became effective in October 2010, which establishes 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 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 must be removed within one year of the cessation of operations. If the Company completes the Dynamic acquisition, these new regulations affecting plugging, abandonment and removal activities may serve to increase, perhaps materially, the future plugging, abandonment and removal costs associated with Dynamic s properties, which may translate into a need to increase the Company s 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.

If the Company completes the Dynamic Acquisition, its estimates of future asset retirement obligations may increase significantly and become more variable from period to period because Dynamic s operations are exclusively 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 increased regulatory scrutiny and the logistical issues associated with working in waters of various depths. 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, if the Company completes the Dynamic acquisition, it may make significant increases or decreases to estimated asset retirement obligations in future periods. For example, because Dynamic operates in the Gulf of Mexico, platforms, facilities and equipment 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, if the Company completes the Dynamic acquisition, its estimates of future asset retirement obligations could differ dramatically from what it may ultimately incur as a result of damage from a hurricane.

If the Company completes the Dynamic acquisition, insurance may not protect the Company against business and operating risks associated with Dynamic s properties.

If the Company completes the Dynamic acquisition, it intends to maintain insurance for some, but not all, of the potential risks and liabilities associated with Dynamic s business. 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, the Company 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 the Company completes the Dynamic acquisition and an accident or other event results in damage to offshore operations, including severe weather, terrorist acts, war, civil disturbances, pollution or environmental damage, occurs and 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.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Information regarding the Company s properties is included in Item 1. Also, refer to Note 25 of the notes to the Company s consolidated financial statements included in Item 8 of this report.

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 Resources, Inc. and SandRidge Energy, Inc. claiming damages based upon alleged

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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. The Company intends to defend this lawsuit vigorously and believes the plaintiffs claims are without merit. This case is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this claim, 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 claim.

On April 5, 2011, Wesley West Minerals, Ltd. and Longfellow Ranch Partners, LP, filed suit against SandRidge Energy, Inc. 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 plaintiffs acreage that results from the treatment of natural gas at the Century Plant. The plaintiffs seek unspecified actual damages, 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 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. The Company intends to defend this lawsuit vigorously. This case is in the early stages and, accordingly, an estimate of reasonably possible losses associated with these claims, 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 claims.

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 SandRidge Energy, Inc., SandRidge Exploration and Production, LLC (SandRidge E&P) and certain directors and senior executive officers of SandRidge Energy, Inc. (collectively, the defendants), in the U.S. District Court for the District of Connecticut. The plaintiffs allege that the defendants made false and misleading statements to U.S. Drilling Capital Management LLC and 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. This case is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this claim, 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 claim.

SandRidge is a defendant in lawsuits from time to time in the normal course of business. In management s opinion, based on currently available information, the Company is not currently involved in any other legal proceedings that, individually or in the aggregate, could have a material adverse effect on its financial condition, operations or cash flows.

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
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
2010		
Fourth Quarter	$ 7.49	$ 4.85
Third Quarter	$ 6.79	$ 3.87
Second Quarter	$ 8.03	$ 5.20
First Quarter	$ 11.08	$ 7.13

On February 17, 2012, there were 286 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 its cash for the operation and expansion of its business, including exploration, development and production activities. In addition, the terms of the Company s indebtedness restrict its ability to pay dividends to holders of its common stock. Accordingly, if the Company s dividend policy were to change in the future, its ability to pay dividends would be subject to these restrictions and the Company s then-existing conditions, including its results of operations, financial condition, contractual obligations, capital requirements, business prospects and other factors deemed relevant by its board of directors.

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, beginning in December 2010, are immediately retired as repurchased. See Note 17 to the consolidated financial statements included in Item 8 of this report for further discussion of treasury stock. During the quarter ended December 31, 2011, 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, 2011 October 31, 2011	24,724	$ 6.11	N/A	N/A
November 1, 2011 November 30, 2011	6,643	$ 7.34	N/A	N/A
December 1, 2011 December 31, 2011	1,079	$ 7.50	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 Arena Acquisition, effective July 16, 2010, and the Forest Acquisition, effective December 21, 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,				
	2011	2010	2009	2008	2007
	(In thousands, except per share data)				
Statement of Operations Data					
Revenues	$ 1,415,213	$ 931,736	$ 591,044	$ 1,181,814	$ 677,452
Expenses					
Production	322,877	237,863	169,880	159,545	106,192
Production taxes	46,069	29,170	4,010	30,594	19,557
Drilling and services	65,654	22,368	28,380	22,872	44,211
Midstream and marketing	66,007	90,149	80,608	189,428	94,253
Depreciation and depletion oil and natural gas	326,614	275,335	176,027	290,917	173,568
Depreciation and amortization other	53,630	50,776	50,865	70,448	53,541
Impairment	2,825		1,707,150	1,867,497	
General and administrative	148,643	179,565	100,256	109,372	61,780
(Gain) loss on derivative contracts	(44,075)	50,872	(147,527)	(211,439)	(60,732)
(Gain) loss on sale of assets	(2,044)	2,424	26,419	(9,273)	(1,777)
Total operating expenses	986,200	938,522	2,196,068	2,519,961	490,593
Income (loss) from operations	429,013	(6,786)	(1,605,024)	(1,338,147)	186,859
Other income (expense)					
Interest income	240	296	375	3,569	4,694
Interest expense	(237,572)	(247,738)	(185,691)	(147,027)	(117,185)
Loss from extinguishment of debt	(38,232)				
Income from equity investments			1,020	1,398	4,372
Other income, net	3,122	2,558	7,272	1,454	729
Total other expense	(272,442)	(244,884)	(177,024)	(140,606)	(107,390)
Income (loss) before income taxes	156,571	(251,670)	(1,782,048)	(1,478,753)	79,469
Income tax (benefit) expense	(5,817)	(446,680)	(8,716)	(38,328)	29,524
Net income (loss)	162,388	195,010	(1,773,332)	(1,440,425)	49,945
Less: net income (loss) attributable to noncontrolling interest(1)	54,323	4,445	2,258	855	(276)
Net income (loss) attributable to SandRidge Energy, Inc	108,065	190,565	(1,775,590)	(1,441,280)	50,221
Preferred stock dividends and accretion	55,583	37,442	8,813	16,232	39,888
Income available (loss applicable) to SandRidge Energy, Inc., common stockholders	$ 52,482	$ 153,123	$ (1,784,403)	$ (1,457,512)	$ 10,333
Earnings (loss) per share information					
Basic.	$ 0.13	$ 0.52	$ (10.20)	$ (9.36)	$ 0.09
Diluted	$ 0.13	$ 0.52	$ (10.20)	$ (9.36)	$ 0.09

Weighted average number of SandRidge Energy, Inc., common shares outstanding					
Basic	398,851	291,869	175,005	155,619	108,828
Diluted	406,645	315,349	175,005	155,619	110,041

(1) 2011 net income attributable to noncontrolling interest includes amounts attributable to third-party unitholders of the Mississippian Trust I and Permian Trust.

	As of December 31,				
	2011	2010	2009	2008	2007
	(In thousands)				
Balance Sheet Data					
Cash and cash equivalents	$ 207,681	$ 5,863	$ 7,861	$ 636	$ 63,135
Property, plant and equipment, net	$ 5,389,424	$ 4,733,865	$ 2,433,643	$ 3,175,559	$ 3,337,410
Total assets	$ 6,219,609	$ 5,231,448	$ 2,780,317	$ 3,655,058	$ 3,630,566
Long-term debt	$ 2,814,176	$ 2,909,086	$ 2,578,938	$ 2,375,316	$ 1,067,649
Redeemable convertible preferred stock(1)	$	$	$	$	$ 450,715
Total equity	$ 2,548,950	$ 1,547,483	$ (195,905)	$ 793,551	$ 1,771,563
Total liabilities and equity	$ 6,219,609	$ 5,231,448	$ 2,780,317	$ 3,655,058	$ 3,630,566

(1) On May 7, 2008, the Company converted all of its then outstanding redeemable convertible preferred stock into shares of its common stock.

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 information in the discussion and analysis below includes the activities of the Mississippian Trust I and the Permian Trust, including amounts attributable to noncontrolling interests. The Company s discussion and analysis relates to the following subjects:

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

Results by Segment

The Company operates in three business segments: exploration and production, drilling and oil field services and midstream gas services. The activities of the Mississippian Trust I and the Permian Trust are included in the exploration and production segment. The All Other column in the tables below includes items not related to the Company s reportable segments, including its CO_2 gathering and sales operations and corporate operations. 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 and amortization. Results of these measurements provide important information to the Company about the activity and profitability of the Company s lines of business. Set forth in the table below is financial information regarding each of the Company s business segments for the years ended December 31, 2011, 2010 and 2009 (in thousands).

	Exploration and Production	Drilling and Oil Field Services	Midstream Gas Services	All Other	Consolidated Total
Year Ended December 31, 2011					
Revenues	$ 1,237,565	$ 390,485	$ 183,912	$ 10,535	$ 1,822,497
Inter-segment revenue	(265)	(287,187)	(118,731)	(1,101)	(407,284)
Total revenues	$ 1,237,300	$ 103,298	$ 65,181	$ 9,434	$ 1,415,213
Income (loss) from operations(1)	$ 521,117	$ 10,341	$ (12,975)	$ (89,470)	$ 429,013
Interest income (expense), net	509	(95)	(611)	(237,135)	(237,332)
Loss on extinguishment of debt				(38,232)	(38,232)
Other income (expense), net	3,601		(485)	6	3,122
Income (loss) before income taxes	$ 525,227	$ 10,246	$ (14,071)	$ (364,831)	$ 156,571
Capital expenditures(2)	$ 1,714,222	$ 25,674	$ 38,514	$ 54,615	$ 1,833,025
Depreciation, depletion and amortization	$ 328,753	$ 32,582	$ 4,650	$ 14,259	$ 380,244

	Exploration and Production	Drilling and Oil Field Services	Midstream Gas Services	All Other	Consolidated Total
Year Ended December 31, 2010					
Revenues	$ 779,450	$ 265,262	$ 275,071	$ 35,285	$ 1,355,068
Inter-segment revenue	(259)	(236,687)	(176,549)	(9,837)	(423,332)
Total revenues	$ 779,191	$ 28,575	$ 98,522	$ 25,448	$ 931,736
Income (loss) from operations(1)	$ 88,390	$ (9,970)	$ 3,959	$ (89,165)	$ (6,786)
Interest income (expense), net	496	(920)	(649)	(246,369)	(247,442)
Other income, net	1,251		625	682	2,558
Income (loss) before income taxes	$ 90,137	$ (10,890)	$ 3,935	$ (334,852)	$ (251,670)
Capital expenditures(2)	$ 1,027,933	$ 31,658	$ 48,401	$ 21,661	$ 1,129,653
Depreciation, depletion and amortization	$ 278,110	$ 30,031	$ 4,030	$ 13,940	$ 326,111
Year Ended December 31, 2009					
Revenues	$ 457,397	$ 225,227	$ 299,580	$ 30,654	$ 1,012,858
Inter-segment revenue	(261)	(201,641)	(215,667)	(4,245)	(421,814)
Total revenues	$ 457,136	$ 23,586	$ 83,913	$ 26,409	$ 591,044
Loss from operations(1)	$ (1,487,914)	$ (15,166)	$ (36,989)	$ (64,955)	$ (1,605,024)
Interest income (expense), net	1,121	(2,074)	(1,246)	(183,117)	(185,316)
Other income, net	4,673		3,365	254	8,292
Loss before income taxes	$ (1,482,120)	$ (17,240)	$ (34,870)	$ (247,818)	$ (1,782,048)
Capital expenditures(2)	$ 555,809	$ 4,090	$ 52,425	$ 32,818	$ 645,142
Depreciation, depletion and amortization	$ 178,783	$ 28,221	$ 5,496	$ 14,392	$ 226,892

(1) Exploration and production segment income (loss) from operations includes net (gains) losses of ($44.1) million, $50.9 million and ($147.5) million on commodity derivative contracts for the years ended December 31, 2011, 2010 and 2009, respectively. The loss from operations for the exploration and production segment for the year ended December 31, 2009 includes a non-cash full cost ceiling impairment of $1,693.3 million on the Company s oil and natural gas properties. The loss from operations for the midstream gas services segment for the year ended December 31, 2009 includes a $26.1 million loss on the sale of gathering and compression assets in the Piñon Field.

(2) On an accrual basis and excluding acquisitions.

Exploration and Production Segment

The Company currently 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. 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 helps ensure that it has adequate funds available for its capital expenditure programs.

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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. Annual comparisons of production and price data are presented in the tables below. Changes in the Company s results for these periods reflect the strategic movement toward increased oil production in 2010 and 2011, including the acquisition of oil and natural gas properties from Forest in December 2009 and Arena in July 2010, which increased oil production volumes and revenues attributable to the Company s exploration and production segment.

	Year Ended December 31, 2011	Year Ended December 31, 2010	Change Amount	Change Percent
Production data				
Oil (MBbls)(1)	11,830	7,386	4,444	60.2%
Natural gas (MMcf)	69,306	76,226	(6,920)	(9.1)%
Total volumes (MBoe)	23,381	20,090	3,291	16.4%
Average daily total volumes (MBoe/d)	64.1	55.0	9.1	16.5%
Average prices as reported(2)				
Oil (per Bbl)(1)	$ 83.21	$ 66.89	$ 16.32	24.4%
Natural gas (per Mcf)	$ 3.50	$ 3.68	$ (0.18)	(4.9)%
Total (per Boe)	$ 52.47	$ 38.56	$ 13.91	36.1%
Average prices including impact of derivative contract settlements				
Oil (per Bbl)(1)	$ 76.41	$ 68.15	$ 8.26	12.1%
Natural gas (per Mcf)	$ 3.27	$ 6.20	$ (2.93)	(47.3)%
Total (per Boe)	$ 48.35	$ 48.58	$ (0.23)	(0.5)%

	Year Ended December 31, 2010	Year Ended December 31, 2009	Change Amount	Change Percent
Production data				
Oil (MBbls)(1)	7,386	2,894	4,492	155.2%
Natural gas (MMcf)	76,226	87,461	(11,235)	(12.8)%
Total volumes (MBoe)	20,090	17,471	2,619	15.0%
Average daily total volumes (MBoe/d)	55.0	47.9	7.1	14.8%
Average prices as reported(2)				
Oil (per Bbl)(1)	$ 66.89	$ 55.62	$ 11.27	20.3%
Natural gas (per Mcf)	$ 3.68	$ 3.36	$ 0.32	9.5%
Total (per Boe)	$ 38.56	$ 26.03	$ 12.53	48.1%
Average prices including impact of derivative contract settlements				
Oil (per Bbl)(1)	$ 68.15	$ 59.69	$ 8.46	14.2%
Natural gas (per Mcf)	$ 6.20	$ 7.20	$ (1.00)	(13.9)%
Total (per Boe)	$ 48.58	$ 45.95	$ 2.63	5.7%

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

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

Exploration and Production Segment Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Exploration and production segment revenues increased $458.1 million, or 58.8%, to $1.2 billion in the year ended December 31, 2011 from 2010, as a result of a 60.2% increase in oil production and a 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 a 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 the continued focus on increased 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 from Arena produced 4,132 MBbls of oil, including production from additional wells drilled on the acquired properties, for the year ended December 31, 2011 compared to 1,548 MBbls 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.

The average price received for the Company s oil production increased 24.4%, or $16.32 per barrel, to $83.21 per barrel during the year ended December 31, 2011 from $66.89 per barrel during 2010. The average price received for the Company s natural gas production for the year ended December 31, 2011 decreased 4.9%, or $0.18 per Mcf, to $3.50 per Mcf from $3.68 per Mcf in 2010.

Due to the long-term nature of the Company s investment in the development of its properties, the Company enters into oil and natural gas swaps and collars for a portion of its production in order to stabilize future cash inflows for planning purposes. 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 from the settlement of derivative contracts with contractual maturities outside of the reporting period are not considered in the calculation of effective prices. The effective price received for oil for the year ended December 31, 2011 was $76.41 per Bbl compared to $68.15 per Bbl during 2010. The effective price received for natural gas for the year ended December 31, 2011 was $3.27 per Mcf compared to $6.20 per Mcf during 2010. This decrease in the effective price received for natural gas is primarily due to not having natural gas fixed price swap contracts in place for a majority of natural gas production in 2011.

During the year ended December 31, 2011, the exploration and production segment reported a $44.1 million net gain on its commodity derivative positions ($50.7 million realized loss and $94.8 million unrealized gain) compared to a $50.9 million net loss on its commodity derivative positions ($224.3 million realized gain and $275.2 million unrealized loss) in 2010. 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 on the Company s oil price swaps. Net realized gains totaling $48.1 million ($111.0 million realized gains and $62.9 million realized losses) resulting from settlements of commodity derivative contracts with original contractual maturities after the quarterly period in which they were settled (out-of-period settlements) were included in the net realized loss for the year ended December 31, 2011. The realized gain 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. Realized gains totaling $114.4 million resulting from out-of-period settlements were included in the realized gain for the year ended December 31, 2010. Unrealized gains or losses on derivative contracts represent the change in fair value of open derivative contracts during the period. The unrealized gain on the Company s commodity derivative contracts recorded during the year ended December 31, 2011 was primarily attributable to existing contract prices on the Company s oil price swaps exceeding average oil market prices as of December 31, 2011. 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.

For the year ended December 31, 2011, the Company had income from operations of $521.1 million in its exploration and production segment compared to $88.4 million in 2010. An increase of $452.0 million in oil and natural gas revenues was slightly offset by increases of $85.0 million in production expense, $16.9 million in production taxes and $51.3 million in depreciation and depletion on oil and natural gas properties during the year ended December 31, 2011. Additionally, the Company recorded a $44.1 million net gain on its commodity derivative contracts for the year ended December 31, 2011 compared to a $50.9 million net loss in 2010. See further discussion of these changes under Consolidated Results of Operations below.

Exploration and Production Segment Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Exploration and production segment revenues increased $322.1 million, or 70.5%, to $779.2 million in the year ended December 31, 2010 from $457.1 million in 2009, primarily as a result of the 155.2% increase in oil production, slightly offset by the 12.8% decrease in natural gas production volumes. Also contributing to the increase was a 48.1% increase in the combined average price the Company received on its oil and natural gas production. In the year ended December 31, 2010, oil production increased by 4,492 MBbls to 7,386 MBbls. The increase in oil production was due to the addition of Permian Basin properties acquired from Forest and Arena, and a focus on increased oil drilling in 2010. The Company produced 3,774 MBbls of oil for the year ended December 31, 2010 from the properties acquired from Forest and Arena. The 11.2 Bcf decrease in natural gas production was a result of the decline in the number of rigs drilling for natural gas during 2010 due to depressed natural gas prices and the Company s strategic shift to increased oil drilling.

The average price received for the Company s oil production increased 20.3%, or $11.27 per barrel, to $66.89 per barrel during the year ended December 31, 2010 from $55.62 per barrel in 2009. The average price the Company received for its natural gas production for the year ended December 31, 2010 increased 9.5%, or $0.32 per Mcf, to $3.68 per Mcf from $3.36 per Mcf in 2009. Including the impact of derivative contract settlements, the effective price received for oil for the year ended December 31, 2010 was $68.15 per Bbl compared to $59.69 per Bbl in 2009. Including the impact of derivative contract settlements, the effective price received for natural gas for the year ended December 31, 2010 was $6.20 per Mcf compared to $7.20 per Mcf in 2009.

During the year ended December 31, 2010, the exploration and production segment reported a $50.9 million net loss on its commodity derivative positions ($224.3 million realized gain and $275.2 million unrealized loss) compared to a $147.5 million net gain on its commodity derivative positions ($348.0 million realized gain and $200.5 million unrealized loss) in 2009. The realized gain of $224.3 million 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. Realized gains totaling $114.4 million resulting from out-of-period settlements were included in the realized gain for the year ended December 31, 2010. The unrealized loss on the Company s commodity contracts recorded during the year ended December 31, 2010 was primarily attributable to an increase in average oil prices at December 31, 2010 compared to the average oil prices at December 31, 2009 or the contract price for contracts entered into during 2010 and the settlement of natural gas price swaps during the year ended December 31, 2010. The unrealized loss for the year ended December 31, 2009 was attributable to increased average oil and natural gas prices and decreases in the price differentials on the Company s basis swaps at December 31, 2009.

For the year ended December 31, 2010, the Company had income from operations of $88.4 million in its exploration and production segment compared to a loss from operations of $1,487.9 million in 2009. The $320.1 million increase in oil and natural gas revenues and the absence of a full cost pool ceiling impairment were partially offset by the $50.9 million net loss on commodity derivative contracts, a $68.0 million increase in production expenses, a $25.2 million increase in production taxes and a $99.3 million increase in depreciation and depletion on oil and natural gas properties. See discussion of production expense, production taxes and depreciation and depletion under Consolidated Results of Operations below.

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.

As of December 31, 2011, the Company owned 31 drilling rigs, through Lariat. The table below presents a summary of the Company s rigs for each of the years ended December 31, 2011, 2010 and 2009:

	December 31,		
Rigs	**2011**	**2010**	**2009**
Working for SandRidge	20	20	14
Working for third parties	10	9	2
Idle		2	14
Total operational	30	31	30
Non-operational(1)	1		1
Total rigs	31	31	31

(1) Includes a rig stacked at December 31, 2011 and a rig being serviced at December 31, 2009.

The table below presents certain information concerning the Company s rigs and contract drilling operations:

	Year Ended December 31,		
	2011	**2010**	**2009**
Average number of operational rigs owned during the period	30.8	27.5	30.0
Average drilling revenue per day per rig working for third parties(1)	$ 15,215	$ 14,287	$ 11,398

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

Until April 15, 2009, the Company indirectly owned, through Lariat and its partner Clayton Williams Energy, Inc. (CWEI), an additional 11 operational rigs through an investment in Larclay L.P. (Larclay). Although the Company s ownership in Larclay afforded it access to Larclay s rigs, it did not control Larclay, and, therefore, did not consolidate the results of its operations with the Company s. On April 15, 2009, Lariat completed an assignment to CWEI of Lariat s 50% equity interest in Larclay pursuant to the terms of an Assignment and Assumption Agreement (the Larclay Assignment) entered into between Lariat and CWEI. Pursuant to the Larclay Assignment, Lariat assigned all of its right, title and interest in and to Larclay to CWEI effective April 15, 2009, and CWEI assumed all of the obligations and liabilities of Lariat relating to Larclay. As the Company had fully impaired its investment in and notes receivable due from Larclay at December 31, 2008, there were no additional losses on Larclay during the year ended December 31, 2009 or as a result of the Larclay Assignment.

Drilling and Oil Field Services Segment Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Drilling and oil field services segment revenues increased $74.7 million to $103.3 million in the year ended December 31, 2011 from the year ended December 31, 2010 and drilling and oil field services segment expenses increased $54.4 million during the same period to $93.0 million. 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. During 2011, an average of ten rigs were working for third parties compared to an average of four rigs working for third parties during 2010. 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.

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Drilling and Oil Field Services Segment Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Drilling and oil field services segment revenues increased to $28.6 million in the year ended December 31, 2010 from $23.6 million in the year ended December 31, 2009 and drilling and oil field services segment expenses decreased $0.2 million to $38.5 million during the same period. The increase in revenues was primarily attributable to an increase in the number of rigs working for third parties during 2010. During 2010, an average of four rigs were working for third parties compared to an average of one rig working for third parties during 2009. Additionally, the average daily rate received per rig working for third parties increased to $14,287 during 2010 compared to $11,398 during 2009. Reduced, or stand-by, rates received on two of the Company s rigs during 2009 resulted in a lower average rate per rig per working day in 2009. During 2010, none of the Company s rigs received stand-by rates. The increase in the number of rigs working for third parties and the average daily rate received from third parties resulted in a reduced loss from operations of $10.0 million in the year ended December 31, 2010 compared to $15.2 million in 2009.

Midstream Gas Services Segment

Midstream gas services segment revenues consist mostly of revenue from gas marketing, which is a very low-margin business. Midstream gas 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 gas business is priced at a published daily or monthly index price. The primary factors affecting the results of the Company s midstream gas services segment are the quantity of natural gas the Company gathers, treats and markets and the prices it pays and receives for natural gas.

In June 2009, the Company completed the sale of its gathering and compression assets located in the Piñon Field. Net proceeds from the sale were approximately $197.5 million, which resulted in a loss on the sale of $26.1 million. In conjunction with the sale, the Company entered into a gas gathering agreement and an operations and maintenance agreement. Under the gas gathering agreement, the Company has dedicated its Piñon Field acreage for priority gathering services through June 30, 2029 and will pay a fee for such services that was negotiated at arms length. Pursuant to the operations and maintenance agreement, the Company will operate and maintain the gathering system assets sold through June 30, 2029 unless the Company or the buyer of the assets chooses to terminate the agreement.

Grey Ranch Plant, L.P. (GRLP) is a limited partnership that operates the Company s Grey Ranch plant located in Pecos County, Texas. The Company purchased its 50% interest in GRLP during 2003. During October 2009, the Company executed amendments to certain agreements related to the ownership and operation of GRLP. As a result of these amendments, the Company became the primary beneficiary of GRLP and began consolidating the activity of GRLP in its midstream gas services segment prospectively beginning on October 1, 2009, the effective date of the amendments.

Midstream Gas Services Segment Year Ended December 31, 2011 Compared to Year Ended December 31, 2010

Midstream gas services segment revenues for the year ended December 31, 2011 were $65.2 million compared to $98.5 million in 2010. The decrease in revenue was due to a decrease in third-party volumes the Company marketed of approximately 5.5 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 revenue 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.

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Midstream Gas Services Segment Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Midstream gas services segment revenues for the year ended December 31, 2010 were $98.5 million compared to $83.9 million in the same period in 2009. Income from operations was $4.0 million for the year ended December 31, 2010 compared to a loss from operations of $37.0 million in 2009. An increase in natural gas prices for third-party volumes the Company marketed in the year ended December 31, 2010 compared to 2009 contributed to the increase in revenues. The consolidation of GRLP activity into the midstream gas services segment for the year ended December 31, 2010 also contributed to the increase in midstream gas services segment revenues and to the increase in income from operations. Prior to October 1, 2009 when the Company began consolidating GRLP, its share of GRLP activity was reported as income from equity investments. The 2010 increase in income from operations was primarily due to the inclusion of a $26.1 million loss on the sale of the Company s gathering and compression assets and a $10.0 million impairment on its spare parts inventory in the year ended December 31, 2009.

Consolidated Results of Operations

Year Ended December 31, 2011 Compared to the Year Ended December 31, 2010

Revenues. Total revenues increased 51.9% for the year ended December 31, 2011 compared to 2010 primarily due to the increase in oil and natural gas sales and an increase in drilling and services revenue.

	Year Ended December 31,			
	2011	2010	$ Change	% Change
		(In thousands)		
Revenues				
Oil and natural gas	$ 1,226,794	$ 774,763	$ 452,031	58.3%
Drilling and services	103,298	28,543	74,755	261.9%
Midstream and marketing	66,690	100,118	(33,428)	(33.4)%
Other	18,431	28,312	(9,881)	(34.9)%
Total revenues	$ 1,415,213	$ 931,736	$ 483,477	51.9%

Total oil and natural gas revenues increased $452.0 million for the year ended December 31, 2011 compared to 2010, as a result of an increase in the amount of oil produced and the average price received for oil production, offset slightly by a decrease in the amount of natural gas produced and the average prices received for natural gas production. The 4,444 MBbl, or 60.2%, increase in oil production was due primarily to the 2,584 MBbl increase in production from properties acquired from Arena due to the inclusion of a full year of production and continued development of the Arena properties. During 2011, the Company completed and commenced production on a total of 943 gross (892 net) wells, including wells drilled on properties acquired from Arena. The average price received for oil production, excluding the impact of derivative contracts, increased 24.4% in the 2011 period to $83.21 per Bbl compared to $66.89 per Bbl in 2010.

Drilling and services revenues increased $74.8 million for the year ended December 31, 2011 compared to 2010 due to an increase in the average number of rigs and the average daily rate received per rig working for third parties and an increase in oil field services work performed for third parties. During the year ended December 31, 2011, the Company had an average of ten rigs working for third parties compared to an average of four rigs working for third parties in 2010. These rigs earned an average of $15,215 per day during 2011 compared to an average of $14,287 per day in 2010.

Midstream and marketing revenues decreased $33.4 million, or 33.4%, in the year ended December 31, 2011 compared to the year ended December 31, 2010. The decrease was attributable to a decrease in third-party volumes the Company marketed due to decreased natural gas production, a decrease in natural gas prices and a decrease in natural gas volumes processed at the Company s gas treating plants for the year ended December 31, 2011 compared to 2010.

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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.

Expenses. Total expenses increased $47.7 million or 5.1% for the year ended December 31, 2011 from 2010 primarily due to increases in production expense, drilling and services expense and depreciation and depletion on oil and natural gas properties, which were partially offset by a decrease in general and administrative expenses. Additionally, the Company recognized a gain on derivative contracts during 2011 compared to a loss during 2010.

	Year Ended December 31,			
	2011	2010	$ Change	% Change
		(In thousands)		
Expenses				
Production	$ 322,877	$ 237,863	$ 85,014	35.7%
Production taxes	46,069	29,170	16,899	57.9%
Drilling and services	65,654	22,368	43,286	193.5%
Midstream and marketing	66,007	90,149	(24,142)	(26.8)%
Depreciation and depletion oil and natural gas	326,614	275,335	51,279	18.6%
Depreciation and amortization other	53,630	50,776	2,854	5.6%
Impairment	2,825		2,825	100.0%
General and administrative	148,643	179,565	(30,922)	(17.2)%
(Gain) loss on derivative contracts	(44,075)	50,872	(94,947)	(186.6)%
(Gain) loss on sale of assets	(2,044)	2,424	(4,468)	(184.3)%
Total expenses	$ 986,200	$ 938,522	$ 47,678	5.1%

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 $85.0 million 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 $16.9 million, or 57.9%, due to increased oil production, including production from properties acquired from Arena and newly producing wells, in the year ended December 31, 2011 compared to 2010.

Drilling and services expenses, which include operating expenses attributable to the drilling and oil field services segment and the Company s CO_2 services companies, 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 $24.1 million, or 26.8%, 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 during the year ended December 31, 2011.

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 an increase of 16.4% in the Company s combined production volume as well as an increase in the depreciation and depletion per Boe to $13.97 in 2011 from $13.70 per Boe in 2010 that resulted from the sale of oil and natural gas properties in 2011.

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In 2011, the Company recorded an impairment of $2.8 million on certain midstream compressor assets as their future use was limited.

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.

The Company recorded a net gain of $44.1 million ($50.7 million realized loss and $94.8 million unrealized gain) on its commodity derivative contracts for the year ended December 31, 2011 compared to a net loss of $50.9 million ($224.3 million realized gain and $275.2 million unrealized loss) in 2010. See further discussion of gains and losses on commodity derivative contracts under Results by Segment Exploration and Production Segment.

Other Income (Expense), Taxes and Net Income Attributable to Noncontrolling Interest. Changes in other income (expense), taxes and net income attributable to noncontrolling interest are reflected in the table below.

	Year Ended December 31, 2011	2010	$ Change	% Change
		(In thousands)		
Other income (expense)				
Interest income	$ 240	$ 296	$ (56)	(18.9)%
Interest expense	(237,572)	(247,738)	10,166	(4.1)%
Loss on extinguishment of debt	(38,232)		(38,232)	(100.0)%
Other income, net	3,122	2,558	564	22.0%
Total other expense	(272,442)	(244,884)	(27,558)	11.3%
Income (loss) before income taxes	156,571	(251,670)	408,241	(162.2)%
Income tax benefit	(5,817)	(446,680)	440,863	(98.7)%
Net income	162,388	195,010	(32,622)	(16.7)%
Less: net income attributable to noncontrolling interest	54,323	4,445	49,878	1,122.1%
Net income attributable to SandRidge Energy, Inc.	$ 108,065	$ 190,565	$ (82,500)	(43.3)%

Interest expense decreased $10.2 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 in interest expense on the senior credit facility, due to lower average outstanding balances in 2011, and 8.625% Senior Notes, due to the purchase and redemption of these notes, for the year ended December 31, 2011, were partially offset by interest expense on the Company s 7.5% Senior Notes issued in March 2011.

In connection with the tender offer to purchase and the redemption of the 8.625% Senior Notes, the Company recognized a loss on extinguishment of debt of $38.2 million for the year ended December 31, 2011. The loss represents the premium paid to purchase and redeem these notes and the unamortized debt issuance costs associated with the notes.

In the second quarter of 2011, the Company completed its valuation of assets acquired and liabilities assumed related to the Arena Acquisition in order to finalize the purchase price allocation. In connection therewith, the Company recorded an additional net deferred tax liability of $7.0 million associated with the Arena Acquisition. Management determined that it is more likely than not that the Company will now realize a benefit from more of its existing deferred tax assets as the additional Arena deferred tax liabilities are available to offset the reversal of the Company s deferred tax assets. As a result of recording an additional net deferred tax liability, the Company released a corresponding portion of its previously recorded valuation allowance resulting in a deferred tax benefit. In the third quarter of 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 $5.8 million net tax benefit for the year ended December 31, 2011 is primarily comprised of the benefit associated with 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 $54.3 million for the year ended December 31, 2011 compared to $4.4 million for the same period in 2010 due to the completion of the Mississippian Trust I s initial public offering in April 2011 and the Permian Trust s initial public offering in August 2011, as it reflects the portion of net income attributable to beneficial interests of the trusts held by third parties.

Year Ended December 31, 2010 Compared to the Year Ended December 31, 2009

Revenues. Total revenues increased 57.6% to $931.7 million for the year ended December 31, 2010 from $591.0 million in 2009. This increase is primarily due to the increase in oil and natural gas sales that resulted from increased oil production and increased prices received on the Company s oil and natural gas production.

	Year Ended December 31, 2010	Year Ended December 31, 2009	$ Change	% Change
		(In thousands)		
Revenues				
Oil and natural gas	$ 774,763	$ 454,705	$ 320,058	70.4%
Drilling and services	28,543	23,586	4,957	21.0%
Midstream and marketing	100,118	86,028	14,090	16.4%
Other	28,312	26,725	1,587	5.9%
Total revenues	$ 931,736	$ 591,044	$ 340,692	57.6%

Total oil and natural gas revenues increased $320.1 million for the year ended December 31, 2010 compared to 2009, primarily as a result of increased oil production, offset slightly by decreased natural gas production, and increased prices received for the Company s oil and natural gas production. The increase in oil production was primarily due to the addition of properties acquired from Forest in late 2009 and Arena in mid-2010 and a focus on increased oil drilling in 2010. The average price received for oil production, excluding the impact of derivative contracts, increased 20.3% in 2010 to $66.89 per Bbl from $55.62 in 2009. The average price received for natural gas production, excluding the impact of derivative contracts, increased 9.5% in 2010 to $3.68 per Mcf from $3.36 in 2009.

Drilling and services revenues increased 21.0% for the year ended December 31, 2010 compared to 2009. The increase was due to an increase in the number of rigs drilling for third parties and an increase in the average revenue per rig per day.

Midstream and marketing revenues increased $14.1 million, or 16.4%, for the year ended December 31, 2010 compared to 2009. The increase in revenues was primarily attributable to the inclusion of GRLP activity for the year ended December 31, 2010 and an increase in the price of natural gas marketed for third parties.

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Operating Costs and Expenses. Total operating costs and expenses decreased to $938.5 million during 2010, compared to $2,196.1 million in 2009, primarily due to the absence of a full cost ceiling impairment during 2010. The absence of a ceiling impairment was partially offset by increases in production expense, production taxes, midstream and marketing expense, depreciation and depletion on oil and natural gas properties, general and administrative expense and the loss on derivative contracts.

	Year Ended December 31, 2010	2009	$ Change	% Change
		(In thousands)		
Operating costs and expenses				
Production	$ 237,863	$ 169,880	$ 67,983	40.0%
Production taxes	29,170	4,010	25,160	627.4%
Drilling and services	22,368	28,380	(6,012)	(21.2)%
Midstream and marketing	90,149	80,608	9,541	11.8%
Depreciation and depletion oil and natural gas	275,335	176,027	99,308	56.4%
Depreciation and amortization other	50,776	50,865	(89)	(0.2)%
Impairment		1,707,150	(1,707,150)	(100.0)%
General and administrative	179,565	100,256	79,309	79.1%
Loss (gain) on derivative contracts	50,872	(147,527)	198,399	(134.5)%
Loss on sale of assets	2,424	26,419	(23,995)	(90.8)%
Total operating costs and expenses	$ 938,522	$ 2,196,068	$ (1,257,546)	(57.3)%

Production expense increased $68.0 million for the year ended December 31, 2010 compared to 2009 primarily due to the addition of operating expenses associated with properties acquired from Forest and Arena. Also contributing to the increase were higher production costs associated with oil volumes compared to production costs on natural gas volumes. Oil production increased by 4,492 MBbls to 7,386 MBbls in 2010.

Production taxes increased $25.2 million due to the additional taxes for production from properties acquired from Forest and Arena and a decrease in the amount of high-cost gas severance tax refunds received in the year ended December 31, 2010 compared to 2009. As a result, production taxes on a unit-of-production basis increased from $0.23 per Boe for 2009 to $1.45 per Boe for 2010.

Drilling and services expenses decreased $6.0 million, or 21.2%, for the year ended December 31, 2010 compared to 2009 due, in part, to higher CO_2 volumes used by the Company in the completion operations of wells on its oil and natural gas properties. Also contributing to the decrease in expense was the overall increase in rig activity and higher profit margins experienced in 2010, which resulted in a higher amount of costs associated with the drilling business being allocated to the full cost pool and a decreased amount of such costs being expensed.

Midstream and marketing expenses increased $9.5 million, or 11.8%, due to the consolidation of GRLP activity as well as increased prices paid for natural gas purchased from third parties during 2010 compared to 2009.

Depreciation and depletion of the Company s oil and natural gas properties increased to $275.3 million for the year ended December 31, 2010 from $176.0 million in 2009. The increase was primarily due to an increase in the Company s depreciation and depletion rate to $13.70 per Boe in 2010 from $10.08 per Boe in 2009 as a result of an increase to the Company s depreciable oil and natural gas properties, primarily due to the acquisition of properties from Arena in July 2010 and Forest in December 2009.

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During 2009, the Company reduced the carrying value of its oil and natural gas properties by $1,693.3 million due to full cost ceiling limitations at both March 31, 2009 and December 31, 2009. There were no full cost ceiling impairments recorded during 2010. There were additional impairment expenses of $10.0 million and $3.9 million in 2009 related to the decline in market value of the Company s spare parts inventory and buildings, respectively, that it determined will not have use or value in the future.

General and administrative expenses increased $79.3 million, or 79.1%, for the year ended December 31, 2010 compared to 2009 due, in part, to a $25.8 million increase in compensation costs resulting from an increase in non-cash stock compensation and an increase in the number of employees and severance expense during 2010. The increased compensation costs are primarily a result of the Arena Acquisition. Also contributing to the increase was $17.0 million in costs incurred related to the Company s acquisition of Arena, $18.2 million for the settlement of a dispute with certain working interest owners and an increase of approximately $8.0 million in professional services rendered to the Company.

The Company recorded a net loss of $50.9 million ($224.3 million realized gain and $275.2 million unrealized loss) on its commodity derivative contracts for the year ended December 31, 2010 compared to a net gain of $147.5 million ($348.0 million realized gain and $200.5 million unrealized loss) in 2009. See further discussion of gains and losses on commodity derivative contracts under Results by Segment Exploration and Production Segment above.

Loss on sale of assets decreased $24.0 million, or 90.8%, for the year ended December 31, 2010 from a $26.4 million loss in 2009, primarily due to a $26.1 million loss recorded on the sale of the Company s gathering and compression assets during the 2009 period.

Other Income (Expense), Taxes and Net Income Attributable to Noncontrolling Interest. Changes in other income (expense), income tax benefit and net income attributable to noncontrolling interest are reflected in the table below.

	Year Ended December 31,			
	2010	2009	$ Change	% Change
		(In thousands)		
Other income (expense)				
Interest income	$ 296	$ 375	$ (79)	(21.1)%
Interest expense	(247,738)	(185,691)	(62,047)	33.4%
Income from equity investments		1,020	(1,020)	(100.0)%
Other income, net	2,558	7,272	(4,714)	(64.8)%
Total other expense	(244,884)	(177,024)	(67,860)	38.3%
Loss before income taxes	(251,670)	(1,782,048)	1,530,378	(85.9)%
Income tax benefit	(446,680)	(8,716)	(437,964)	5,024.8%
Net income (loss)	195,010	(1,773,332)	1,968,342	(111.0)%
Less: net income attributable to noncontrolling interest	4,445	2,258	2,187	96.9%
Net income (loss) attributable to SandRidge Energy, Inc.	$ 190,565	$ (1,775,590)	$ 1,966,155	(110.7)%

Interest expense increased to $247.7 million for the year ended December 31, 2010 from $185.7 million in 2009. This increase was primarily attributable to higher average debt balances outstanding during the year ended December 31, 2010 compared to 2009 mainly due to increased borrowings under the Company s senior credit facility during the period and the issuance of the Company s 9.875% Senior Notes due 2016 in May 2009 and its 8.75% Senior Notes due 2020 in December 2009. Also contributing to the increase was a $16.5 million net loss on the Company s interest rate swaps for the year ended December 31, 2010 compared to a $5.8 million net loss for 2009.

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Other income, net decreased to $2.6 million in 2010 from $7.3 million in 2009 due primarily to a break-up fee received in 2009 as a result of the termination of an acquisition transaction.

The Company reported an income tax benefit of $446.7 million, net of income tax expense attributable to noncontrolling interest, for the year ended December 31, 2010, compared to an income tax benefit of $8.7 million for 2009. The increase was primarily due to the release of a portion of the Company s valuation allowance against its net deferred tax asset as a result of the Arena Acquisition. Net deferred tax liabilities recorded as a result of the Arena Acquisition in July 2010 reduced the Company s existing net deferred tax asset position, allowing a corresponding reduction in the valuation allowance against the net deferred tax asset.

Liquidity and Capital Resources

The Company s primary sources of liquidity and capital resources are cash flow generated from operations, borrowings under the Company s senior credit facility, the issuance of equity and debt securities and proceeds from sales or other monetization of assets. As described in Item 1 Business 2011 Developments, during 2011, the Company raised approximately $2.0 billion, net of certain fees, post-closing adjustments and redemptions, through royalty trust offerings, asset monetizations and senior note issuances. Additionally, as described in Item 1 Business 2012 Developments, the Company received approximately $272.5 million in January 2012 from the sale of working interests in the Mississippian formation, and could realize proceeds from the proposed Mississippian Trust II offering in 2012.

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

Working Capital

The Company s working capital balance fluctuates as a result of the timing and amount of borrowings or repayments under its senior credit facility and changes in the fair value of its outstanding commodity derivative instruments. Absent any significant effects from its commodity derivative instruments, the Company typically maintains 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 generally uses excess cash to pay down borrowings outstanding under its credit arrangements.

At December 31, 2011, the Company had a working capital deficit of $257.7 million compared to a deficit of $368.9 million at December 31, 2010. Current assets increased $266.3 million at December 31, 2011, compared to current assets at December 31, 2010, primarily due to a $201.8 million increase in cash and cash equivalents, as a result of proceeds received in November 2011 from the sale of the Company s east Texas properties, and a $60.2 million increase in accounts receivable due to an increase in oil production and prices received on oil production. Current liabilities increased $155.0 million, primarily due to a $129.9 million increase in accounts payable and accrued expenses resulting from increased production and drilling activity.

The Company expects to fund its planned capital expenditures budget, debt service requirements and working capital needs for 2012 from cash flows from operating activities, its existing cash balances, availability under its senior credit facility, proceeds from the sale of working interests in the Mississippian formation in January 2012, proceeds from the proposed Mississippian Trust II offering, other potential monetizations of assets and potential access to capital markets. However, a significant portion of the Company s 2012 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.

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Cash Flows

The Company s cash flows for the years ended December 31, 2011, 2010 and 2009 are presented in the following table and discussed below:

	Year Ended December 31, 2011	2010 (In thousands)	2009
Cash flows provided by operating activities	$ 475,485	$ 390,128	$ 311,559
Cash flows used in investing activities	(918,860)	(962,753)	(1,247,059)
Cash flows provided by financing activities	645,193	570,627	942,725
Net increase (decrease) in cash and cash equivalents	$ 201,818	$ (1,998)	$ 7,225

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; third-party demand for its drilling rigs and oil field services and the rates it is able to charge for these services; and the margins it obtains from its natural gas and CO_2 gathering and treating contracts.

Net cash provided by operating activities for the years ended December 31, 2011 and 2010 was $475.5 million and $390.1 million, respectively. The increase in cash provided by operating activities in 2011 compared to 2010 was primarily due 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 realized losses on the Company s commodity derivative contracts in 2011 compared to realized gains in 2010.

Net cash provided by operating activities for the years ended December 31, 2010 and 2009 was $390.1 million and $311.6 million, respectively. The increase in cash provided by operating activities in 2010 compared to 2009 was primarily due to a 48.1% increase in the average prices the Company received for its oil and natural gas production, and increased oil production resulting from the properties acquired from Forest and Arena and a focus on increased oil drilling 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 decreased to $918.9 million in the year ended December 31, 2011 from $962.8 million in 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.

Cash flows used in investing activities decreased to $962.8 million in the year ended December 31, 2010 from $1,247.1 million in 2009 primarily due to the use of equity to fund the majority of the Arena Acquisition in July 2010 rather than cash, which was used to purchase the properties acquired from Forest in 2009. This was partially offset by increased capital expenditures during 2010.

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

	Year Ended December 31, 2011	2010 (In thousands)	2009
Capital expenditures			
Exploration and production	$ 1,714,222	$ 1,027,933	$ 555,809
Drilling and oil field services	25,674	31,658	4,090
Midstream gas services	38,514	48,401	52,425
Other	54,615	21,661	32,818
Capital expenditures, excluding acquisitions	1,833,025	1,129,653	645,142
Acquisitions(1)	34,628	138,428	795,074
Total	$ 1,867,653	$ 1,268,081	$ 1,440,216

(1) 2010 acquisition expenditures include only the cash portion of the Arena Acquisition.

Cash Flows from Financing Activities

The Company s financing activities provided $645.2 million in cash for the year ended December 31, 2011 compared to $570.6 million in 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 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, as well as the premium paid on extinguishment of $30.3 million in connection with the purchase and redemption, $340.0 million of net repayments under the senior credit facility, $57.4 million of distributions to third-party royalty trust unitholders and $56.7 million of dividends paid on the Company s convertible perpetual preferred stock.

The Company s financing activities provided $570.6 million in cash for the year ended December 31, 2010 compared to $942.7 million in 2009. Cash provided by financing activities during 2010 was primarily comprised of $328.0 million of net borrowings, representing borrowings under the Company s senior credit facility reduced by payments on its debt and $290.7 million of net proceeds from the issuance of 3,000,000 shares of the Company s 7.0% convertible perpetual preferred stock, offset slightly by the payment of dividends on its 8.5% convertible perpetual preferred stock and its 6.0% convertible perpetual preferred stock and debt issuance costs. Cash provided by financing activities during the year ended December 31, 2009 was generated primarily by the private placements of an aggregate of 4,650,000 shares of the Company s convertible perpetual preferred stock and the registered underwritten offering of 40,080,000 shares common stock that provided combined proceeds of approximately $768.0 million, the majority of which were used to pay down amounts outstanding under the senior credit facility.

Indebtedness

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. Effective March 15, 2011, the borrowing base was reduced to $790.0 million due to the issuance of the Company s 7.5% Senior Notes. 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. Outstanding letters of credit affect the availability under the senior credit facility on a dollar-for-dollar basis. The senior credit facility matures on April 15, 2014, unless the Company s Senior Floating Rate Notes due 2014 (Senior Floating Rate Notes) have not been refinanced by December 31, 2013, in which case the senior credit facility will mature on January 31, 2014.

On February 23, 2011, the Company s senior credit facility was amended to, among other things, (a) exclude from the calculation of Consolidated Net Income the net income (or loss) of a Royalty Trust, except to the extent of cash distributions received by the Company, (b) establish that an investment in a Royalty Trust and dispositions to, and of interests in, Royalty Trusts are permitted, (c) clarify that a Royalty Trust is not a Subsidiary, (d) allow the Company to net against its calculation of Consolidated Funded Indebtedness cash balances exceeding $10.0 million in the event no loans are outstanding under the senior credit facility at that time and (e) establish that, for any fiscal quarter ending prior to March 31, 2012, if the ratio of the Company s secured indebtedness to EBITDA is less than 1.5:1.0, then compliance with the Company s Consolidated Leverage Ratio covenant is not required. Terms capitalized in the preceding sentence have the meaning given to them in the senior credit facility agreement, as amended.

On April 20, 2011, the senior credit facility was amended to permit the Company to pay cash dividends on its 7.0% convertible perpetual preferred stock. In October 2011, the borrowing base was reaffirmed at $790.0 million. On December 22, 2011, the senior credit facility was further amended to establish that, for any fiscal quarter ending prior to March 31, 2013, if the ratio of the Company s secured indebtedness to EBITDA is less than 1.5:1.0, then compliance with the Company s Consolidated Leverage Ratio covenant is not required. Terms capitalized in the preceding sentence have the meaning given to them in the senior credit facility agreement, as amended.

As of December 31, 2011, the senior credit facility contained financial covenants, including maintaining agreed levels for the (i) ratio of total funded debt to EBITDA, which may not exceed 4.5:1.0 at each quarter end, calculated using the last four completed fiscal quarters, unless, for any quarter ending prior to March 31, 2013, the ratio of the Company s secured indebtedness to EBITDA is less than 1.5:1.0, calculated using the last four completed fiscal quarters, (ii) ratio of current assets to current liabilities, which must be at least 1.0:1.0 at each quarter end (in the current ratio calculation (as defined in the senior credit facility), 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) and (iii) ratio of the Company s secured indebtedness to EBITDA, which may not exceed 2.0:1.0 at each quarter end, calculated using the last four completed fiscal quarters. The Company remains in compliance with all applicable financial covenants under the senior credit facility.

Senior Notes. On March 15, 2011, the Company issued $900.0 million of its 7.5% Senior Notes. Net proceeds were used to fund the tender offer for and redemption of the 8.625% Senior Notes, discussed below, and to repay amounts outstanding under the Company s senior credit facility.

On March 28, 2011, the Company completed a cash tender offer to purchase all of the $650.0 million aggregate principal amount of its 8.625% Senior Notes. The Company purchased approximately 94.5%, or $614.2 million, of these notes in the tender offer. On April 1, 2011, the Company redeemed the remaining outstanding $35.8 million aggregate principal amount of its 8.625% Senior Notes.

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

Long-term debt. Long-term obligations under outstanding debt agreements consist of the following at December 31, 2011 (in thousands):

Senior credit facility	$
Other notes payable	16,029
Senior Floating Rate Notes due 2014	350,000
9.875% Senior Notes due 2016, net of $10,921 discount	354,579
8.0% Senior Notes due 2018	750,000
8.75% Senior Notes due 2020, net of $6,432 discount	443,568
7.5% Senior Notes due 2021	900,000
Total debt	$ 2,814,176

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The indentures governing the senior notes referred to above contain limitations on the incurrence of indebtedness, payment of dividends, investments, asset sales, certain asset purchases, transactions with related parties and consolidations or mergers.

For more information about the senior credit facility, senior notes and the Company s other long-term debt obligations, see Note 13 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*.

Outlook

The Company s 2012 budget for capital expenditures, including expenditures related to its drilling programs for the Mississippian Trust I and the Permian Trust, as well as the proposed Mississippian Trust II, and excluding acquisitions and capital expenditures associated with properties to be acquired from Dynamic, is approximately $1.7 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 entered into development agreements with the Mississippian Trust I and the Permian Trust that obligates 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, 2014 and March 31, 2015, respectively. In the event of delays, the Company will have until December 31, 2015 and March 31, 2016 to fulfill its drilling obligations to the Mississippian Trust I and the Permian Trust, respectively. The estimated costs to drill the remaining wells under these obligations were approximately $539.0 million at December 31, 2011. Additionally, the Company has incurred, and will have to continue to incur, capital expenditures to achieve production targets contained in certain gathering and treating arrangements.

The Company is dependent on the availability of borrowings under its senior credit facility, along with cash flows from operating activities and proceeds from planned asset sales and other asset monetizations, to fund those capital expenditures. Based on current cash balances, anticipated oil and natural gas prices, availability under the Company s senior credit facility, anticipated proceeds from the sales or other monetizations of assets and potential access to the capital markets, the Company expects to be able to fund its planned capital expenditures budget, debt service requirements and working capital needs for 2012. The Company plans to fund a portion of its 2012 budget for capital expenditures with existing cash balances, proceeds received from the sale of working interest in the Mississippian play in January 2012 and the proposed initial public offering of Mississippian Trust II. 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. If the Company completes its pending acquisition of Dynamic, it will issue to the seller approximately 74 million shares of the Company s common stock and pay the seller $680.0 million in cash. The Company has secured $725.0 million in committed financing for the acquisition that it may use to fund the cash portion of the acquisition. The Company expects any capital and operating expenditures relating to Dynamic s assets to be funded by the cash flow generated by such assets.

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 2012 through 2014, fixed price swap contracts are in place for only a portion of expected oil production for 2015. No fixed price swap contracts are in place for the Company s natural gas production beyond 2012 or oil production beyond 2015. For more information about the Company s commodity derivative contracts, see Note 14 to the

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consolidated financial statements included in Item 8 of this report. 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.

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, 2011, the Company s cash and cash equivalents were $207.7 million, including $4.9 million attributable to the Company s consolidated VIEs which is available to satisfy only the VIE s obligations. The Company had approximately $2.8 billion in total debt outstanding and $28.5 million in outstanding letters of credit with no amount outstanding under its senior credit facility at December 31, 2011. As of and for the year ended December 31, 2011, the Company was in compliance with applicable covenants under all of its senior notes and senior credit facility. As of February 21, 2012, the Company s cash and cash equivalents were approximately $205.2 million, including $5.2 million attributable to the Company s consolidated VIEs, which is available to satisfy only the VIE s obligations. Additionally, there was no amount outstanding under the Company s senior credit facility and $28.2 million outstanding in letters of credit.

Contractual Obligations

A summary of the Company s contractual obligations as of December 31, 2011 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)	$ 4,349,893	$ 218,975	$ 777,458	$ 753,013	$ 2,600,447
Gas gathering and transportation agreements	524,223	74,537	129,031	106,905	213,750
Purchase obligation	22,780	12,444	10,336		
Third-party drilling rig and hydraulic fracturing agreements(2)	82,108	30,211	51,897		
Asset retirement obligations	128,116	32,906	1,204	3,095	90,911
Operating leases and other	18,703	7,008	5,546	1,740	4,409
Total	$ 5,125,823	$ 376,081	$ 975,472	$ 864,753	$ 2,909,517

(1) Includes interest on long-term debt. Interest rates as of December 31, 2011 were used to determine future interest payments on the Senior Floating Rate Notes.
(2) 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.

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 had an obligation relating to its non-qualified deferred compensation plan of $13.6 million as of December 31, 2011. Amounts are distributed to participating employees in accordance with the plan guidelines.

The Company s development agreements with the Mississippian Trust I and the Permian Trust 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, 2014 and March 31, 2015, respectively. In the event of delays, the Company will have until December 31, 2015 and March 31, 2016 to fulfill its drilling obligation to the Mississippian Trust I and the Permian Trust, respectively. The estimated cost to fulfill the drilling obligations remaining at December 31, 2011 totaled approximately $539.0 million.

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 a discussion of the Company s significant accounting policies.

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 2011, 2010 and 2009. 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, the most significant variable of which is the estimate of future commodity prices. Estimates of future prices are based upon published forward commodity price curves for oil and natural gas instruments. Valuation also incorporates adjustments for the nonperformance risk of the Company s counterparties.

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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, the most significant variable of which is the estimate of future interest rate yields. These estimates of future yields are based upon utilizing forward curves such as the London Interbank Offered Rate (LIBOR) provided by third parties. Valuation also incorporates adjustments for the nonperformance risk of the Company s counterparties.

Proved Reserves. Approximately 96.1% of the Company s reserves were estimated by independent petroleum engineers for the year ended December 31, 2011. 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 very complex 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, 2011, 2010 and 2009, the Company revised its proved reserves from prior years reports by approximately (36.8) MMBoe, 157.7 MMBoe and (198.7) MMBoe, respectively, due to market prices during or at the end of the applicable period or production performance indicating more (or less) reserves in place or 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 provided 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 reserve quantities of a cost center.

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

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

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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. During the year ended December 31, 2009, total capitalized costs of the Company s oil and natural gas properties exceeded its ceiling limitation resulting in a non-cash ceiling impairment of $1,693.3 million. There were no full cost ceiling impairments recorded during 2010 or 2011.

Unproved Properties. The balance of unproved properties consists of capital costs incurred for undeveloped acreage, wells and production facilities in progress and wells pending determination, together with capitalized interest costs for these projects. 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 items classified as unproved property 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 six-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 3 to 39 years. 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.

Goodwill. 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 1st 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 a weighted average cost of capital rate to estimate the fair value for the reporting unit. The Company s first annual evaluation of goodwill was completed during the third quarter of 2011 and resulted in no impairment loss. 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 percent, no impairment charge 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. The Company has not identified any such indicators as of December 31, 2011 that would require an impairment test prior to the Company s next annual goodwill evaluation.

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 statements 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 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 gas 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 gas 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.

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, 2011, 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.

New Accounting Pronouncements

For a discussion of recently adopted accounting standards and recent accounting standards not yet adopted, see Note 1 to the Company s consolidated financial statements included in Item 8 of this report.

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

General

The discussion in this section 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 of the Company s commodity derivative 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 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 protection swaps. The Company s oil and diesel 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 natural gas fixed price swap transactions are settled based upon New York Mercantile Exchange prices, and the Company s natural gas basis protection swap transactions are settled based upon the index price of natural gas at the Waha hub, a west Texas gas marketing and delivery center, and the Houston Ship Channel. Settlement for oil and diesel derivative contracts occurs in the succeeding month or quarter and natural gas derivative contracts are settled in the production month. The Company s natural gas collars are settled based upon the New York Mercantile Exchange prices on the penultimate commodity business day for the relevant contract. Natural gas collars only result in a cash settlement when the settlement price exceeds the fixed-price ceiling or falls below the fixed-price floor.

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.

See Note 14 to the Company s consolidated financial statements included in Item 8 of this report for a summary of its open commodity derivative contracts.

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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, 2011, 2010 and 2009 (in thousands):

	Year Ended December 31,		
	2011	**2010**	**2009**
Commodity Derivatives			
Realized loss (gain)(1)	$ 50,713	$ (224,337)	$ (348,022)
Unrealized (gain) loss	(94,788)	275,209	200,495
(Gain) loss on commodity derivative contracts	$ (44,075)	$ 50,872	$ (147,527)

(1) Includes $48.1 million net realized gains ($111.0 million realized gains and $62.9 million realized losses) for the year ended December 31, 2011 related to out-of-period settlements. Includes $114.4 million of realized gains for the year ended December 31, 2010 related to out-of-period settlements. There were no commodity derivative contracts settled prior to the contractual maturity during 2009.

Credit Risk. All of the Company s hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions 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 rating 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. Additionally, the majority of the Company s counterparties are lenders under its senior credit facility. Under certain circumstances, a default by the Company under its senior credit facility constitutes a default under its hedging transactions. 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 hedging 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 can be offset against amounts owed to such counterparty under the Company s senior credit facility under certain circumstances. As of December 31, 2011, the counterparties to the Company s derivative contracts consisted of 22 financial institutions, 21 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 counterparties to the Company s derivative contracts share in the collateral supporting the Company s senior credit facility.

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 26 financial institutions with commitments ranging from 0.57% to 5.41%.

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 may enter into derivative transactions to fix the interest rate on its variable rate debt. At December 31, 2011, the Company had a $350.0 million notional interest rate swap agreement, which effectively serves to fix the rate on the Senior Floating Rate Notes at an annual rate of 6.69% through April 1, 2013. This swap has not been designated as a hedge.

The Company s interest rate swap reduces its market risk on its Senior Floating Rate Notes. The Company uses sensitivity analyses to determine the impact that market risk exposures could have on the Company s variable interest rate borrowings if not for its interest rate swap. Based on the $350.0 million outstanding balance of the Company s Senior Floating Rate Notes at December 31, 2011, a one percent change in the applicable rates, with all other variables held constant, would have resulted in a change in the Company s interest expense of approximately $3.5 million for the year ended December 31, 2011.

The following table summarizes the cash settlements and valuation gains and losses, which are included in interest expense in the Company s consolidated income statement, on the Company s interest rate swaps for the years ended December 31, 2011, 2010 and 2009 (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Interest Rate Swaps			
Realized loss	$ 9,414	$ 8,145	$ 6,229
Unrealized (gain) loss	(6,246)	8,395	(446)
Loss on interest rate swaps	$ 3,168	$ 16,540	$ 5,783

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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.

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, 2011 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, as appropriate to allow timely decisions regarding required disclosure.

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

Changes in Internal Control over Financial Reporting. There were no changes in the Company s internal control over financial reporting during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Item 9B. ***Other Information***

Not applicable.

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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, 2012: Director Biographical Information, Executive Officers, Compliance with Section 16(a) of the Exchange Act and Corporate Governance Matters.

Item 11. ***Executive Compensation***

The information required by this item is incorporated herein by reference to the following sections of the Company s definitive proxy statement, which will be filed no later than April 30, 2012: Director Compensation, Outstanding Equity Awards and Executive Officers and Compensation.

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

The information required by this item is incorporated herein by reference to the following sections of the Company s definitive proxy statement, which will be filed no later than April 30, 2012: Equity Compensation Plan Information and Security Ownership of Certain Beneficial Owners and Management.

Item 13. ***Certain Relationships and Related Transactions and Director Independence***

The information required by this item is incorporated herein by reference to the following sections of the Company s definitive proxy statement, which will be filed no later than April 30, 2012: Related Party Transactions and Corporate Governance Matters.

Item 14. ***Principal Accounting Fees and Services***

The information required by this item is incorporated herein by reference to the section captioned Ratification of Selection of Independent Registered Public Accounting Firm in the Company s definitive proxy statement, which will be filed no later than April 30, 2012.

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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 Rule 13a-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.

Based on our evaluation on criteria for effective internal control over financial reporting described in *Internal Control Integrated Framework*, our management concluded, that as of December 31, 2011, our internal control over financial reporting was effective.

The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report that follows.

/s/ Tom L. Ward	/s/ James D. Bennett
Tom L. Ward	**James D. Bennett**
Chief Executive Officer	**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 of cash flows present fairly, in all material respects, the financial position of SandRidge Energy, Inc. and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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, 2011, 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.

As discussed in Note 1 to the consolidated financial statements, the Company uses the 12-month average price to calculate the ceiling test. Prior to the adoption of the SEC s final rule, *Modernization of the Oil and Gas Reporting Requirements* on December 31, 2009, the Company used the period end price for purposes of the ceiling test calculation.

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

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

/s/ PRICEWATERHOUSECOOPERS LLP
PricewaterhouseCoopers LLP

Tulsa, Oklahoma

February 27, 2012

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SandRidge Energy, Inc., and Subsidiaries

Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
	(In thousands)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 207,681	$ 5,863
Accounts receivable, net	206,336	146,118
Derivative contracts	4,066	5,028
Inventories	6,903	3,945
Other current assets	16,854	14,636
Total current assets	441,840	175,590
Oil and natural gas properties, using full cost method of accounting		
Proved (includes development and project costs excluded from amortization of $231.3 million and $186.5 million)	8,969,296	8,159,924
Unproved	689,393	547,953
Less: accumulated depreciation, depletion and impairment	(4,791,534)	(4,483,736)
	4,867,155	4,224,141
Other property, plant and equipment, net	522,269	509,724
Restricted deposits	27,912	27,886
Derivative contracts	26,415	
Goodwill	235,396	234,356
Other assets	98,622	59,751
Total assets	$ 6,219,609	$ 5,231,448
LIABILITIES AND EQUITY		
Current liabilities		
Current maturities of long-term debt	$ 1,051	$ 7,293
Accounts payable and accrued expenses	506,784	376,922
Billings and estimated contract loss in excess of costs incurred	43,320	31,474
Derivative contracts	115,435	103,409
Asset retirement obligation	32,906	25,360
Total current liabilities	699,496	544,458
Long-term debt	2,813,125	2,901,793
Derivative contracts	49,695	124,173
Asset retirement obligation	95,210	94,517
Other long-term obligations	13,133	19,024
Total liabilities	3,670,659	3,683,965
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, 2011 and December 31, 2010; aggregate liquidation preference of $265,000	3	3
6.0% Convertible perpetual preferred stock; 2,000 shares issued and outstanding at December 31, 2011 and December 31, 2010; aggregate liquidation preference of $200,000	2	2
7.0% Convertible perpetual preferred stock; 3,000 shares issued and outstanding at December 31, 2011 and December 31, 2010; aggregate liquidation preference of $300,000	3	3
Common stock, $0.001 par value, 800,000 shares authorized; 412,827 issued and 411,953 outstanding at December 31, 2011 and 406,830 issued and 406,360 outstanding at December 31, 2010	399	398

Additional paid-in capital	4,568,856	4,528,912
Treasury stock, at cost	(6,158)	(3,547)
Accumulated deficit	(2,937,094)	(2,989,576)
Total SandRidge Energy, Inc stockholders equity	1,626,011	1,536,195
Noncontrolling interest	922,939	11,288
Total equity	2,548,950	1,547,483
Total liabilities and equity	$ 6,219,609	$ 5,231,448

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,		
	2011	2010	2009
	(In thousands, except per share amounts)		
Revenues			
Oil and natural gas	$ 1,226,794	$ 774,763	$ 454,705
Drilling and services	103,298	28,543	23,586
Midstream and marketing	66,690	100,118	86,028
Other	18,431	28,312	26,725
Total revenues	1,415,213	931,736	591,044
Expenses			
Production	322,877	237,863	169,880
Production taxes	46,069	29,170	4,010
Drilling and services	65,654	22,368	28,380
Midstream and marketing	66,007	90,149	80,608
Depreciation and depletion oil and natural gas	326,614	275,335	176,027
Depreciation and amortization other	53,630	50,776	50,865
Impairment	2,825		1,707,150
General and administrative	148,643	179,565	100,256
(Gain) loss on derivative contracts	(44,075)	50,872	(147,527)
(Gain) loss on sale of assets	(2,044)	2,424	26,419
Total expenses	986,200	938,522	2,196,068
Income (loss) from operations	429,013	(6,786)	(1,605,024)
Other income (expense)			
Interest income	240	296	375
Interest expense	(237,572)	(247,738)	(185,691)
Loss on extinguishment of debt	(38,232)		
Income from equity investments			1,020
Other income, net	3,122	2,558	7,272
Total other expense	(272,442)	(244,884)	(177,024)
Income (loss) before income taxes	156,571	(251,670)	(1,782,048)
Income tax benefit	(5,817)	(446,680)	(8,716)
Net income (loss)	162,388	195,010	(1,773,332)
Less: net income attributable to noncontrolling interest	54,323	4,445	2,258
Net income (loss) attributable to SandRidge Energy, Inc.	108,065	190,565	(1,775,590)
Preferred stock dividends	55,583	37,442	8,813
Income available (loss applicable) to SandRidge Energy, Inc., common stockholders	$ 52,482	$ 153,123	$ (1,784,403)
Earnings (loss) per share			
Basic	$ 0.13	$ 0.52	$ (10.20)

Diluted	$	0.13	$	0.52	$	(10.20)
Weighted average number of common shares outstanding						
Basic		398,851		291,869		175,005
Diluted		406,645		315,349		175,005

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

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SandRidge Energy, Inc., and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity

	Convertible Perpetual Preferred Stock		Common Stock		Additional		Retained Earnings		
	Shares	Amount	Shares	Amount	Paid-In Capital	Treasury Stock	(Accumulated Deficit)	Noncontrolling Interest	Total
					(In thousands)				
Balance, December 31, 2008		$	166,046	$ 163	$ 2,170,986	$ (19,332)	$ (1,358,296)	$ 30	$ 793,551
Distributions to noncontrolling interest owners								(26)	(26)
Consolidation of Grey Ranch L.P.								7,790	7,790
Issuance of convertible perpetual preferred stock, net	4,650	5			443,205				443,210
Issuance of common stock			40,080	40	324,790				324,830
Purchase of treasury stock						(1,494)			(1,494)
Stock purchase retirement plans			(373)		(602)	(4,253)			(4,855)
Stock-based compensation					27,098				27,098
Stock-based compensation excess tax benefit					(3,864)				(3,864)
Issuance of restricted stock awards, net of cancellations			2,962						
Net (loss) income							(1,775,590)	2,258	(1,773,332)
Convertible perpetual preferred stock dividends							(8,813)		(8,813)
Balance, 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, 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 royalty trusts unitholders								(57,449)	(57,449)
Distributions to noncontrolling interest owners								(2,751)	(2,751)
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, December 31, 2011	7,650	$ 8	411,953	$ 399	$ 4,568,856	$ (6,158)	$ (2,937,094)	$ 922,939	$ 2,548,950

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

	2011	Years Ended December 31, 2010 (In thousands)	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$ 162,388	$ 195,010	$ (1,773,332)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Provision for doubtful accounts	2,511	129	214
Depreciation, depletion and amortization	380,244	326,111	226,892
Impairment	2,825		1,707,150
Debt issuance costs amortization	11,372	11,006	7,477
Discount amortization on long-term debt	2,383	2,153	990
Loss on extinguishment of debt	38,232		
Deferred income taxes	(6,986)	(447,500)	
Unrealized (gain) loss on derivative contracts	(101,034)	283,604	200,049
Realized loss on financing derivatives	6,591		
(Gain) loss on sale of assets	(2,044)	2,424	26,419
Investment loss (income)	115	(460)	(51)
Income from equity investments			(1,020)
Stock-based compensation	38,684	37,681	22,793
Changes in operating assets and liabilities increasing (decreasing) cash			
Receivables	(61,645)	(11,480)	8,760
Inventories	(2,958)	(238)	61
Other current assets	71	8,079	47,317
Billings in excess of costs incurred	(11,013)	(61,180)	(26,490)
Other assets and liabilities, net	(35,773)	2,667	(26,937)
Accounts payable and accrued expenses	51,522	42,122	(108,733)
Net cash provided by operating activities	475,485	390,128	311,559
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures for property, plant and equipment	(1,743,637)	(1,044,371)	(715,205)
Acquisitions of assets, net of cash received of $0, $39,518 and $0, respectively	(34,628)	(138,428)	(795,074)
Proceeds from sale of assets	859,405	204,951	263,220
Deposit received on pending asset sale		10,000	
Refunds of restricted deposits		5,095	
Net cash used in investing activities	(918,860)	(962,753)	(1,247,059)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from borrowings	2,033,000	2,117,914	2,619,607
Repayments of borrowings	(2,130,293)	(1,789,919)	(2,416,975)
Premium on debt redemption	(30,338)		
Debt issuance costs	(20,326)	(12,540)	(18,310)
Proceeds from issuance of royalty trust units	917,528		
Distributions to royalty trust unitholders	(57,449)		
Noncontrolling interest distributions	(2,751)	(3,515)	(26)
Noncontrolling interest contributions		306	
Proceeds from issuance of common stock, net			324,830
Proceeds from issuance of convertible perpetual preferred stock, net	(231)	290,704	443,210
Stock-based compensation excess tax benefit	53	15	(3,864)
Purchase of treasury stock	(13,796)	(7,169)	(5,747)
Dividends paid-preferred	(56,742)	(28,525)	
Cash received on financing derivatives	6,538	3,356	

Net cash provided by financing activities	645,193	570,627	942,725
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	201,818	(1,998)	7,225
CASH AND CASH EQUIVALENTS, beginning of year	5,863	7,861	636
CASH AND CASH EQUIVALENTS, end of year	$ 207,681	$ 5,863	$ 7,861
Supplemental Disclosure of Cash Flow Information			
Cash paid for interest, net of amounts capitalized	$ 224,127	$ 210,112	$ 171,994
Cash paid (received) for income taxes	2,083	(1,508)	2,908
Supplemental Disclosure of Noncash Investing and Financing Activities			
Change in accrued capital expenditures	$ 89,388	$ 85,282	$ (70,063)
Convertible perpetual preferred stock dividends payable	16,572	17,363	8,813
Adjustment to oil and natural gas properties for estimated contract loss	25,000	105,000	
Common stock issued in connection with acquisition		1,246,334	
Stock issued to satisfy settlement		12,200	

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

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 related to the exploitation of its significant holdings in (1) the Mid-Continent area of Oklahoma and Kansas and (2) in west Texas. The Company s primary areas of focus are the Mississippian formation in the Mid-Continent and the Permian Basin in west Texas. The Company owns and operates other interests in the Mid-Continent, West Texas Overthrust (WTO), Gulf Coast and Gulf of Mexico. The Company also operates businesses that are complementary to its primary development and production activities, including gas gathering and processing facilities, an oil and gas marketing business, an oil field services business, including a drilling rig business, and tertiary oil recovery operations.

Principles of Consolidation. The consolidated financial statements include the accounts of SandRidge Energy, Inc. 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 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 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 differ from the 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 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 the Company s cash flows, and while fixed price swap contracts are in place for the majority of expected oil production for 2012 through 2014, fixed price swap contracts are in place for only a portion of expected oil production for 2015. No fixed price swap contracts are in place for the Company s natural gas production beyond 2012 or oil production beyond 2015. See Note 14 for the Company s open oil and natural gas commodity derivative contracts.

The Company has incurred, and will have to continue to incur, capital expenditures to achieve production targets contained in certain gathering and treating arrangements. Additionally, the Company has a drilling obligation, to each of SandRidge Mississippian Trust I (the Mississippian Trust I) and SandRidge Permian Trust (the Permian Trust). See Note 3 for further discussion of these drilling obligations. The Company depends on the availability of borrowings under its senior secured revolving credit facility (the senior credit facility), along with cash flows from operating activities and the proceeds from planned asset sales or other asset monetizations, to fund those capital expenditures. Based on current cash balances, anticipated oil and natural gas prices, anticipated proceeds from sales or other monetizations of assets, availability under the senior credit facility and potential access to the capital markets, the Company expects to be able to fund its planned capital expenditures budget, debt service requirements and working capital needs for 2012. 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.

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 5 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 $0.2 million at December 31, 2011 and $0.1 million at December 31, 2010.

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 4 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 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 4. In accounting for its 2009 and 2010 business acquisitions, the Company determined the fair value of assets acquired and liabilities assumed. See Note 2 for additional discussion of the Company s acquisitions. In 2011, the Company recorded a $2.8 million impairment on certain midstream assets. In 2009, the Company recorded a $10.0 million impairment related to the write-down of its spare parts inventory and a $3.9 million impairment on three buildings on the Company s corporate campus. See Note 8 for discussion of these impairments.

Derivative Financial Instruments. To manage risks related to price fluctuations in oil, natural gas and diesel fuel prices and changes in interest rates, the Company enters into oil, natural gas, diesel fuel 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 and diesel fuel used in its operations. 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 swaps as hedging instruments. As such, the interest rate swap derivatives are 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.

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, internal costs directly related to the Company s acquisition, exploration and development activities and capitalized interest. The Company capitalized internal costs of $37.1 million, $28.6 million and $22.3 million to the full cost pool in 2011, 2010 and 2009, respectively. Capitalized costs are amortized using a unit-of-production method. Under this method, the provision for 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 to unproved leasehold acreage, wells and production facilities in progress and wells pending determination of the existence of proved reserves, together with capitalized interest costs for these projects. 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. Costs associated with wells in progress and completed wells that have yet to be evaluated are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. Costs of dry wells are transferred to the amortization base immediately upon determination that the well is unsuccessful.

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, 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 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 unevaluated 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 8 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 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 3 to 39 years. 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.

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 discussion of impairments.

Capitalized Interest. During 2011 and 2010, interest of approximately $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. There was no interest capitalized to the full cost pool in 2009. An additional $2.0 million and $1.0 million were capitalized in 2011 and 2010, respectively, on midstream and corporate assets which were under construction. There was no interest capitalized on midstream or corporate assets in 2009. Interest is capitalized using a weighted average interest rate based on the Company s outstanding borrowings.

Restricted Deposits. Restricted deposits represent bank trust and escrow accounts required by the Bureau of Ocean Energy Management, Regulation and 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, 2011 and 2010, the Company had $27.9 million of such restricted deposits.

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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 2 for discussion of the 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 evaluating whether goodwill is impaired, 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.

Investments. Investments in affiliated companies are accounted for under the equity method in circumstances where the Company is deemed to exercise significant influence over the operating and investing policies of the investee but does not have control. Under the equity method, the Company recognizes its share of the investee s earnings in its consolidated statement of operations. Investments in affiliated companies not accounted for under the equity method are accounted for under the cost method. 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 its consolidated balance sheet. See Note 10.

Asset Retirement Obligation. 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 is accreted 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 depreciation and depletion oil and natural gas expense 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 obligation.

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 the Company 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 by the Company 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 $1.7 million and $2.1 million at December 31, 2011 and 2010, respectively. The Company includes the gas imbalance positions in other long-term obligations in its consolidated balance sheet.

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 gas 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 gas 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.

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 of 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.

Noncontrolling Interest. Noncontrolling interest in the Company s subsidiaries represents ownership interests in the consolidated entity and is included as a component of equity in the consolidated balance sheet and consolidated statement of changes in equity. At December 31, 2011, noncontrolling interest in the Company s consolidated VIEs and subsidiaries included a 50% interest in Grey Ranch Plant, L.P. (GRLP) and Grey Ranch Plant Genpar, LLC (Genpar), a 61.6% interest in the Mississippian Trust I, a 65.7% interest in the Permian Trust and a 1.29% interest in Cholla Pipeline, LP. At December 31, 2010 and 2009, noncontrolling interest in the Company s consolidated VIEs and subsidiaries included a 50% interest in GRLP and Genpar and a 1.29% interest in Cholla Pipeline, LP. See Note 3 for discussion of the Company s VIEs.

Earnings per Share. Basic earnings per common share is calculated by dividing earnings available to common shareholders 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 shareholders 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 accordingly.

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. The Company maintains cash balances at several financial institutions. Accounts at each institution are insured by the Federal Deposit Insurance Corporation up to $250,000. From time to time, the Company may have balances in these accounts that exceed the federally insured limit. The Company does not anticipate any loss associated with balances exceeding the federally insured limit.

All of the Company s hedging transactions have been carried out in the over-the-counter market. The use of hedging transactions 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 rating 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. Additionally, the majority of the Company s counterparties are lenders under its senior credit facility. Under certain circumstances, a default by the Company under its senior credit facility constitutes a default under its hedging transactions. 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 hedging 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 can be offset against amounts owed to such counterparty under the Company s senior credit facility under certain circumstances. As of December 31, 2011, the counterparties to the Company s derivative contracts consisted of 22 financial institutions, 21 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 counterparties to the Company s derivative contracts share in the collateral supporting the Company s senior credit facility.

The Company operates a substantial portion of its oil and 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 other 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 5 for information regarding the Company s allowance for doubtful accounts.

Recently Adopted Accounting Pronouncements. In January 2010, the Financial Accounting Standards Board (the FASB) issued Accounting Standards Update 2010-06, Fair Value Measurements and Disclosures: Improving Disclosures about Fair Value Measurements (ASU 2010-06), requiring additional disclosures and clarifying existing disclosure requirements about fair value measurement. The Company implemented the new disclosures and clarifications of existing disclosure requirements under ASU 2010-06 effective with the first quarter of 2010, and the disclosure requirements regarding activity in Level 3 fair value measurements in the first quarter of 2011. The implementation of ASU 2010-06 had no impact on the Company s financial position or results of operations. See Note 4 for the discussion of the Company s fair value measurements.

In December 2010, the FASB issued Accounting Standards Update 2010-28, Intangibles Goodwill and Other: When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts (ASU 2010-28), which requires step two of the goodwill impairment test to be performed when the carrying value of a reporting unit is zero or negative, if it is more likely than not that a goodwill impairment exists. The requirements of ASU 2010-28 are effective for fiscal years beginning after December 15, 2010, and were considered with the Company s first annual impairment test performed in July 2011. See Note 9 for discussion of the Company s goodwill and its annual impairment test.

Recent Accounting Pronouncements Not Yet Adopted. In May 2011, the 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 about the application of existing fair value measurements and requires additional disclosure information regarding valuation processes and inputs used. The new disclosure requirements are effective for interim and annual reporting periods beginning after December 15, 2011. As the additional requirements under ASU 2011-04, which will be implemented January 1, 2012, pertain to fair value measurement disclosures, no effect on the Company s financial position or results of operations is expected.

In September 2011, the FASB issued Accounting Standards Update 2011-08, Testing Goodwill for Impairment (ASU 2011-08), which allows an entity the option of performing a qualitative assessment to determine whether it is necessary to perform the current 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, with early adoption permitted. The implementation of ASU 2011-08 will have no impact on the Company s financial position or results of operations.

2. Acquisitions and Divestitures

2009 Acquisitions and Divestitures

The Company completed the following acquisitions and divestitures in 2009:

In June 2009, the Company completed the sale of its gathering and compression assets located in the Piñon Field, which is located in Pecos County and Terrell County, Texas. Net proceeds to the Company were approximately $197.5 million, resulting in a loss of $26.1 million. In conjunction with the sale, the Company entered into a gas gathering agreement and an operations and maintenance agreement. Under the gas gathering agreement, the Company has dedicated its Piñon Field acreage for priority gathering services through June 30, 2029 and the Company will pay a fee that was negotiated at arms length for such services. Pursuant to the operations and maintenance agreement, the Company will operate and maintain the gathering system assets sold through June 30, 2029 unless the Company or the buyer of the assets chooses to terminate the agreement.

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In June 2009, the Company completed the sale of its drilling rights in east Texas below the depth of the Cotton Valley formation. After post-closing adjustments, total net proceeds received were $58.5 million. The sale of the drilling rights was accounted for as an adjustment to the full cost pool with no gain or loss recognized by the Company.

In December 2009, the Company purchased developed and undeveloped oil and natural gas properties located in the Permian Basin from Forest Oil Corporation and one of its subsidiaries (collectively, Forest) for $791.7 million, net of purchase price and post-closing adjustments. The acquisition qualified as a business combination and, as such, the Company estimated the fair value of the properties as of the December 21, 2009 acquisition date, which is the date the Company obtained control of the properties. The Company used a discounted cash flow model, which required assumptions about 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.
The estimated fair value of these properties approximated the consideration paid to Forest, which the Company concluded approximated the fair value that would be paid by a typical market participant. As a result, no goodwill was recognized related to the acquisition. The acquisition-related costs of $0.3 million were expensed as incurred in general and administrative expense in the consolidated statements of operations for each of the years ended December 31, 2010 and 2009. In the third quarter of 2010, the Company completed its valuation of assets acquired and liabilities assumed from Forest with no significant changes to the initial allocation.

The following table summarizes the consideration paid to Forest and the amounts of the assets acquired and liabilities assumed as of December 21, 2009 (in thousands).

Consideration paid to Forest	
Cash, net of accrued purchase price adjustments	$ 795,074
Recognized amounts of identifiable assets acquired and liabilities assumed	
Proved developed and undeveloped properties	754,185
Unproved leasehold properties	52,246
Asset retirement obligation	(11,357)
Total identifiable net assets	$ 795,074

The unaudited financial information in the table below summarizes the combined results of the Company s operations and the properties acquired from Forest, on a pro forma basis, as though the purchase had taken place at the beginning of the year presented. The pro forma information is based on the Company s consolidated results of operations for the year ended December 31, 2009, on historical results of the properties acquired and on estimates of the effect of the transactions to the combined results. The pro forma information is not necessarily indicative of results that actually would have occurred had the transaction been in effect for the period indicated, or of results that may occur in the future.

	2009	
	Actual	**Pro Forma**
	(In thousands)	
		(Unaudited)
Revenues	$ 591,044	$ 682,593
Loss applicable to SandRidge Energy, Inc. common stockholders (1)	$ (1,784,403)	$ (1,949,567)
Loss per common share		
Basic	$ (10.20)	$ (9.72)
Diluted	$ (10.20)	$ (9.72)

(1) Pro forma amount includes $142.9 million of additional estimated impairment from full cost ceiling limitations.

2010 Acquisitions and Divestitures

The Company completed the following acquisitions and divestitures in 2010:

On July 16, 2010, the Company acquired all 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. In addition, outstanding options to purchase Arena common stock that were deemed exercised pursuant to the merger agreement were converted into shares of Company common stock pursuant to the merger agreement, and outstanding shares of Arena restricted common stock were converted into restricted shares of Company common stock pursuant to the merger agreement. Approximately 39.8 million shares of Arena common stock were outstanding on the acquisition date, resulting 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.

In the second quarter of 2011, the Company completed its valuation of assets acquired and liabilities assumed related to the Arena Acquisition. Upon receipt of final confirmatory information for certain accruals and completion of the 2010 Arena federal income tax return in the second quarter of 2011, the Company increased current assets, the net deferred tax liability and the value assigned to goodwill and reduced current liabilities. The accompanying consolidated balance sheet at December 31, 2010 included certain preliminary allocations of the purchase price for the Arena Acquisition. See Note 9 for further discussion of goodwill.

The following table summarizes the final valuation of assets acquired and liabilities assumed in connection with the Arena Acquisition (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

(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. 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. See Note 9 for further discussion of goodwill and Note 19 for further discussion of the net deferred tax liability.

The following unaudited pro forma results of operations are provided for the years ended December 31, 2010 and 2009 as though the Arena Acquisition had been completed as of the beginning of each year presented. The pro forma combined results of operations for the years ended December 31, 2010 and 2009 have been 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 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 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		2009	
	Actual	Pro Forma	Actual	Pro Forma
	(In thousands, except per share data)			
		(Unaudited)		(Unaudited)
Revenues	$ 931,736	$ 1,046,569	$ 591,044	$ 717,285
Income available (loss applicable) to SandRidge Energy, Inc. common stockholders(1)(2)	$ 153,123	$ 171,654	$ (1,784,403)	$ (1,451,838)
Earnings (loss) per common share				
Basic	$ 0.52	$ 0.44	$ (10.20)	$ (3.97)
Diluted	$ 0.52	$ 0.43	$ (10.20)	$ (3.97)

(1) Pro forma columns reflect 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.

(2) Pro forma amount includes approximately $165.0 million of additional estimated impairment from full cost ceiling limitations for the year ended December 31, 2009.

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

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 sale of the deep acreage rights was accounted for as an adjustment to the full cost pool with no gain or loss recognized. The Company retained the shallow rights associated with this acreage.

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On December 10, 2010, the Company sold approximately 40,000 net acres of non-core assets 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. The sale was accounted for as an adjustment to the full cost pool with no gain or loss recognized.

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 September 2011, the Company sold to Atinum MidCon I, LLC (Atinum), a 13.2% non-operated working interest in approximately 860,000 acres (or approximately 113,000 net acres) in the Mississippian formation in northern Oklahoma and southern Kansas. As consideration for the working interest, Atinum paid the Company approximately $287.0 million (including approximately $11.1 million attributable to the Atinum drilling carry described herein and approximately $18.3 million not attributable to the Atinum drilling carry, but to be applied against the Company s future capital expenditures on the properties), subject to post-closing adjustments, and also committed to pay 13.2% of SandRidge s share of drilling and completion costs for wells drilled within an area of mutual interest until an additional $250.0 million has been paid (Atinum drilling carry), which is expected to occur over a three-year period. The amounts received attributable to the Atinum drilling carry will reduce the Company s capital expenditures over the three-year period.

In November 2011, the Company sold its east Texas natural gas properties in Gregg, Harrison, Rusk and Panola counties for $231.0 million, subject to post-closing adjustments.

3. 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.

Grey Ranch Plant, L.P. 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. During October 2009, the Company executed amendments to certain agreements related to the ownership and operation of GRLP. 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. 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. As a result of the amendments in October 2009 discussed above, 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. The Company began consolidating the activity of GRLP in its consolidated financial statements prospectively on October 1, 2009, the effective date of the amendments. The 50% ownership interest not held by the Company is presented as noncontrolling interest in the consolidated financial statements at December 31, 2011 and 2010.

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, 2011 and 2010, $8.2 million and $11.3 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, 2011 and 2010 consisted of the following (in thousands):

	December 31,	
	2011	2010
Cash and cash equivalents	$ 1,702	$ 4,601
Accounts receivable, net	24	181
Inventory	109	109
Other current assets	176	124
Total current assets	2,011	5,015
Other property, plant and equipment, net	14,985	16,079
Total assets	$ 16,996	$ 21,094
Accounts payable and accrued expenses	$ 280	$ 400
Total liabilities	$ 280	$ 400

Grey Ranch Plant Genpar, LLC. 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 serve to 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.

SandRidge Mississippian Trust I. On April 12, 2011, the Mississippian Trust I completed its initial public offering of 17,250,000 common units representing beneficial interests in the Mississippian Trust I. Net proceeds to the Mississippian Trust I, after certain offering expenses, were $336.9 million. Concurrent with the closing, the Company conveyed certain royalty interests to the Mississippian Trust I in exchange for the net proceeds of the offering and 10,750,000 units (3,750,000 common units and 7,000,000 subordinated units) representing approximately 38.4% of the beneficial interest in the Mississippian Trust I. The royalty interests conveyed to the Mississippian Trust I are in certain existing wells and wells to be drilled on certain oil and natural gas properties leased by the Company in the Mississippian formation in northern Oklahoma. The conveyance of the royalty interests to the Mississippian Trust I was recorded in April 2011 at the historical cost to the Company, or $309.0 million, which was determined by allocating the historical net book value of the Company s full cost pool based on the fair value of the conveyed royalty interests relative to the fair value of the Company s full cost pool. The Mississippian Trust I will dissolve and begin to liquidate on December 31, 2030 and will soon thereafter wind up its affairs and terminate. At the time the Mississippian Trust I terminates, 50% of the conveyed royalty interests will automatically revert to the Company.

The Mississippian Trust I makes quarterly cash distributions to its unitholders based on its calculated distributable income. In order to provide support for cash distributions on the Mississippian Trust I s common units, the Company agreed to subordinate a portion of the Mississippian Trust I units it owns (the Mississippian Trust I subordinated units), which constitute 25% of the total outstanding Mississippian Trust I units. The Mississippian Trust I subordinated units are entitled to receive pro rata distributions from the Mississippian Trust I 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 Mississippian Trust I 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. See Note 22 for discussion of the Mississippian Trust I s fourth quarter distribution. In addition, pursuant to a trust agreement, SandRidge has a loan commitment to the Mississippian Trust I, whereby SandRidge will loan funds to the Mississippian Trust I 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 Mississippian Trust I s cash is not sufficient to pay ordinary course administrative expenses as they become due. There were no amounts outstanding under the loan commitment at December 31, 2011.

The Company and one of its wholly owned subsidiaries entered into a development agreement with the Mississippian Trust I that obligates the Company to drill, or cause to be drilled, a specified number of wells, within an area of mutual interest, which are also subject to the royalty interest granted to the Mississippian Trust I, by December 31, 2014. In the event of delays, the Company will have until December 31, 2015 to fulfill its drilling obligation. At the end of the fourth full calendar quarter following satisfaction of the Company s drilling obligation (the Mississippian Trust I subordination period), the Company s Mississippian Trust I subordinated units will automatically convert into common units on a one-for-one basis and the Company s right to receive incentive distributions will terminate. Incentive distributions are equal to 50% of the amount by which the cash available for distribution on all of the Mississippian Trust I units for any quarter exceeds 20% of the target distribution for such quarter. One of the Company s wholly owned subsidiaries also granted to the Mississippian Trust I 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 the drilling costs for the wells. As the Company fulfills its drilling obligation, wells that have been drilled and perforated for completion are released from the lien and the total amount that may be recovered by the Mississippian Trust I is proportionately reduced. As of December 31, 2011, the maximum amount recoverable by the Mississippian Trust I under the lien has been reduced to approximately $94.0 million. Additionally, the Company and the Mississippian Trust I entered into an administrative services agreement, pursuant to which the Company provides certain administrative services to the Mississippian Trust I, and a derivatives agreement, pursuant to which the Company provides to the Mississippian Trust I the economic effects of certain of the Company s derivative contracts. The tables below present open oil and natural gas commodity derivative contracts at December 31, 2011, the economic effects of which will be provided to the Mississippian Trust I under the derivatives agreement. See Note 14 for further discussion of the derivatives agreement between the Company and the Mississippian Trust I.

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Oil Price Swaps

Contract Period	Notional (MBbl)	Weighted Avg. Fixed Price
January 2012 December 2012	454	$ 104.15
January 2013 December 2013	488	$ 102.07
January 2014 December 2014	541	$ 100.94
January 2015 December 2015	468	$ 101.07

Natural Gas Price Swaps

Contract Period	Notional (MMBtu)	Weighted Avg. Fixed Price
January 2012 June 2012	2,190	$ 4.90

Natural Gas Collars

Contract Period	Notional (MMBtu)	Collar Range
July 2012 December 2012	402	$ 4.00 - 6.20
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

The Mississippian Trust I is considered a VIE due to the lack of voting or similar decision-making rights by its equity holders regarding activities that have a significant effect on the economic success of the Mississippian Trust I. The Company s ownership in the Mississippian Trust I and the loan commitment constitute variable interests. The Company has determined it is the primary beneficiary of the Mississippian Trust I as it has (a) the power to direct the activities that most significantly impact the economic performance of the Mississippian Trust I through (i) its participation in the creation and structure of the Mississippian Trust I, (ii) the manner in which it fulfills its drilling obligation to the Mississippian Trust I and (iii) the manner in which it operates the oil and natural gas properties that are subject to the conveyed royalty interests, and (b) through the end of the Mississippian Trust I subordination period, the obligation to absorb losses and right to receive residual returns, through its ownership of the Mississippian Trust I subordinated units, that could potentially be significant to the Mississippian Trust I. As a result, the Company began consolidating the activities of the Mississippian Trust I into its results of operations in April 2011. In consolidation, the common units of the Mississippian Trust I owned by third parties are reflected as noncontrolling interest in the accompanying consolidated financial statements. As discussed above, the Company s Mississippian Trust I subordinated units will automatically convert to Mississippian Trust I common units at the end of the Mississippian Trust I subordination period.

The Mississippian Trust I s assets can only be used to settle its own obligations and not other obligations of the Company. The Mississippian Trust I s creditors have no contractual recourse to the general credit of the Company. Although the Mississippian Trust I is included in the Company s consolidated financial statements, the Company s legal interest in the Mississippian Trust I s assets is limited to its ownership of the Mississippian Trust I units. At December 31, 2011, $348.9 million of noncontrolling interest in the accompanying consolidated balance sheet was attributable to the Mississippian Trust I. The Mississippian Trust I s assets and liabilities, after considering the effects of intercompany eliminations, included in the accompanying consolidated balance sheets at December 31, 2011 consisted of the following (in thousands):

Cash and cash equivalents (1)	$ 1,336
Accounts receivable	7,471
Total current assets	8,807
Investment in royalty interests(2)	308,964
Less: accumulated depletion	(16,844)

	292,120
Total assets	$ 300,927
Accounts payable and accrued expenses	$ 276
Total liabilities	$ 276

(1) Includes $1.0 million held by the trustee as reserves for future general and administrative expenses.
(2) Included in oil and natural gas properties on the accompanying consolidated balance sheet.

SandRidge Permian Trust. On August 16, 2011, the Permian Trust completed its initial public offering of 34,500,000 common units representing beneficial interests in the Permian Trust. Net proceeds to the Permian Trust, after certain offering expenses, were $580.6 million. Concurrent with the closing, the Company conveyed certain royalty interests to the Permian Trust in exchange for the net proceeds of the offering and 18,000,000 units (4,875,000 common units and 13,125,000 subordinated units) representing approximately 34.3% of the beneficial interest in the Permian Trust. The royalty interests conveyed to the Permian Trust are in certain existing wells and wells to be drilled on certain oil and natural gas properties leased by the Company in the Central Basin Platform of the Permian Basin in Andrews County, Texas. The conveyance of the royalty interests to the Permian Trust was recorded in August 2011 at the historical cost to the Company, or $549.8 million, which was determined by allocating the historical net book value of the Company s full cost pool based on the fair value of the conveyed royalty interests relative to the fair value of the Company s full cost pool. The Permian Trust will dissolve and begin to liquidate on March 31, 2031 and will soon thereafter wind up its affairs and terminate. At the time the Permian Trust terminates, 50% of the conveyed royalty interests will automatically revert to the Company.

The Permian Trust makes quarterly cash distributions to its unitholders based on its calculated distributable income. In order to provide support for cash distributions on the Permian Trust s common units, the Company agreed to subordinate a portion of the Permian Trust units it owns (the Permian Trust subordinated units), which constitute 25% of the total outstanding Permian Trust units. The Permian Trust subordinated units are entitled to receive pro rata distributions from the Permian Trust 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 Permian Trust 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. See Note 22 for discussion of the Permian Trust s fourth quarter distribution. In addition, pursuant to a trust agreement, SandRidge has a loan commitment to the Permian Trust, whereby SandRidge will loan funds to the Permian 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 third party, if at any time the Permian Trust s cash is not sufficient to pay ordinary course administrative expenses as they become due. There were no amounts outstanding under the loan commitment at December 31, 2011.

The Company and one of its wholly owned subsidiaries entered into a development agreement with the Permian Trust that obligates the Company to drill, or cause to be drilled, a specified number of wells, within an area of mutual interest, which are also subject to the royalty interest granted to the Permian Trust, by March 31, 2015. In the event of delays, the Company will have until March 31, 2016 to fulfill its drilling obligation. At the end of the fourth full calendar quarter following satisfaction of the Company s drilling obligation (the Permian Trust subordination period), the Company s Permian Trust subordinated units will automatically convert into common units on a one-for-one basis and the Company s right to receive incentive distributions will terminate. Incentive distributions are equal to 50% of the amount by which the cash available for distribution on all of the Permian Trust units for any quarter exceeds 20% of the target distribution for such quarter. One of the Company s wholly owned subsidiaries also granted to the Permian 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 the drilling costs for the wells. As the Company fulfills its drilling obligation, wells that have been drilled and perforated for completion are released from the lien and the total amount that may be recovered by the Permian Trust is proportionately reduced. As of December 31, 2011, the maximum amount recoverable by the Permian Trust under the lien has been reduced to approximately $229.7 million. The Company and the Permian Trust also entered into an administrative services agreement, pursuant to which the Company provides certain administrative services to the Permian Trust, including hedge management services, and a derivatives agreement,

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pursuant to which the Company provides to the Permian Trust the economic effects of certain of the Company s derivative contracts. Substantially concurrent with the execution of the derivatives agreement, the Company novated certain of the derivative contracts underlying the derivatives agreement to the Permian Trust. The tables below present the open contracts at December 31, 2011 underlying the derivatives agreement, including the contracts novated to the Permian Trust. The combined volume in the tables below reflects the total volume of the Permian Trust s oil derivative contracts. See Note 14 for further discussion of the derivatives agreement between the Company and the Permian Trust.

Oil Price Swaps Underlying the Derivatives Agreement

Contract Period		Notional (MBbl)	Weighted Avg. Fixed Price
January 2012	December 2012	687	$ 102.20
January 2013	December 2013	921	$ 102.84
January 2014	December 2014	1,100	$ 101.75
January 2015	March 2015	232	$ 100.90

Oil Price Swaps Underlying the Derivatives Agreement and Novated to the Trust

Contract Period		Notional (MBbl)	Weighted Avg. Fixed Price
January 2012	December 2012	466	$ 102.20
January 2013	December 2013	368	$ 102.84
January 2014	December 2014	311	$ 101.75
January 2015	March 2015	71	$ 100.90

The Permian Trust is considered a VIE due to the lack of voting or similar decision-making rights by its equity holders regarding activities that have a significant effect on the economic success of the Permian Trust. The Company s ownership in the Permian Trust and the loan commitment constitute variable interests. The Company has determined it is the primary beneficiary of the Permian Trust as it has (a) the power to direct the activities that most significantly impact the economic performance of the Permian Trust through (i) its participation in the creation and structure of the Permian Trust, (ii) the manner in which it fulfills its drilling obligation to the Permian Trust, (iii) the manner in which it operates the oil and natural gas properties that are subject to the conveyed royalty interests, and (iv) its role as the Permian Trust s hedge manager, and (b) through the end of the Permian Trust subordination period, the obligation to absorb losses and right to receive residual returns, through its ownership of the Permian Trust subordinated units, that could potentially be significant to the Permian Trust. As a result, the Company began consolidating the activities of the Permian Trust into its results of operations in August 2011. In consolidation, the common units of the Permian Trust owned by third parties are reflected as noncontrolling interest. As discussed above, the Company s Permian Trust subordinated units will automatically convert to Permian Trust common units at the end of the Permian Trust subordination period.

The Permian Trust s assets can only be used to settle its own obligations and not other obligations of the Company. The Permian Trust s creditors have no contractual recourse to the general credit of the Company. Although the Permian Trust is included in the Company s consolidated financial statements, the Company s legal interest in the Permian Trust s assets is limited to its ownership of the Permian Trust units. At December 31, 2011, $565.8 million of noncontrolling interest in the accompanying consolidated balance sheets was attributable to the Permian Trust. The Permian Trust s assets and liabilities, after considering the effects of intercompany eliminations, included in the accompanying consolidated balance sheet at December 31, 2011 consisted of the following (in thousands):

Cash and cash equivalents(1)	$ 1,815
Accounts receivable	10,886
Derivative contracts	1,499
Total current assets	14,200
Investment in royalty interests(2)	549,831
Less: accumulated depletion	(7,560)
	542,271
Derivative contracts	5,668
Total assets	$ 562,139
Accounts payable and accrued expenses	$ 210
Total liabilities	$ 210

(1) Includes $1.0 million held by the trustee as reserves for future general and administrative expenses.
(2) Included in oil and natural gas properties on the accompanying consolidated balance sheet.

Piñon Gathering Company, LLC. The Company has a gas gathering and operations and maintenance agreements 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. 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 Company had accounts receivable due from PGC of $3.2 million and $3.8 million as of December 31, 2011 and 2010, respectively, included in the accompanying consolidated balance sheets. The Company had accounts payable due to PGC of $4.6 million and $6.8 million as of December 31, 2011 and 2010, respectively, included in the accompanying consolidated balance sheets. See Note 16 for amounts due in future periods based on minimum volume requirements under this agreement.

4. 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. At December 31, 2011, the Company had assets and liabilities classified as Level 1, Level 2 and Level 3, as described below. At December 31, 2010, the Company had assets or liabilities classified as Level 1 and Level 3.

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 is deemed to approximate fair value.

Other assets. The fair value of other long-term assets, consisting of assets attributable to the Company s deferred compensation plan, is based on quoted market prices.

Level 2 Fair Value Measurements

Derivative contracts. The fair values of the Company s oil and natural gas fixed price swaps, 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, interest rates and discount rates, or can be corroborated from active markets. 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 values of the Company s diesel fixed price swaps and natural gas basis swaps are based upon quotes obtained from counterparties to the derivative contracts. These values are reviewed internally for reasonableness 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.

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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, 2011

	Fair Value Measurements				Assets/ Liabilities at Fair Value
	Level 1	Level 2	Level 3	Netting(1)	
Assets					
Restricted deposits	$ 27,912	$	$	$	$ 27,912
Commodity derivative contracts		62,746	397	(32,662)	30,481
Other assets	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 swaps		10,448			10,448
	$	$ 193,142	$ 4,650	$ (32,662)	$ 165,130

December 31, 2010

	Fair Value Measurements				Assets/ Liabilities at Fair Value
	Level 1	Level 2	Level 3	Netting(1)	
Assets					
Restricted deposits	$ 27,886	$	$	$	$ 27,886
Commodity derivative contracts			10,576	(5,548)	5,028
Other assets	4,826				4,826
	$ 32,712	$	$ 10,576	$ (5,548)	$ 37,740
Liabilities					
Commodity derivative contracts	$	$	$ 216,436	$ (5,548)	$ 210,888
Interest rate swaps			16,694		16,694
	$	$	$ 233,130	$ (5,548)	$ 227,582

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

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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, 2009, 2010 and 2011 (in thousands):

	Commodity Derivative Contracts	Interest Rate Swaps	Total
Balance of Level 3, January 1, 2009	$ 246,648	$ (8,745)	$ 237,903
Total gains or losses (realized/unrealized)	147,527	(5,783)	141,744
Purchases			
Settlements	(348,022)	6,229	(341,793)
Balance of Level 3, December 31, 2009	46,153	(8,299)	37,854
Total gains or losses (realized/unrealized)	(50,872)	(16,540)	(67,412)
Purchases	23,196		23,196
Settlements	(224,337)	8,145	(216,192)
Balance of Level 3, December 31, 2010	(205,860)	(16,694)	(222,554)
Total gains or losses (realized/unrealized)	44,075	(3,168)	40,907
Settlements	50,713	9,414	60,127
Purchases			
Transfers(1)	106,820	10,448	117,268
Balance of Level 3, December 31, 2011	$ (4,252)	$	$ (4,252)

(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, 2010 and 2009, 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 in and/or out of 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.

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

Fair Value of Debt

The Company measures the fair value of its long-term debt based on quoted market prices which consider the effect of the Company s credit risk. The estimated fair values and carrying values of the Company s senior notes at December 31, 2011 and 2010 were as follows (in thousands):

	December 31, 2011		December 31, 2010	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Senior Floating Rate Notes due 2014	$ 339,381	$ 350,000	$ 334,751	$ 350,000
8.625% Senior Notes due 2015			663,181	650,000
9.875% Senior Notes due 2016(1)	396,568	354,579	394,527	352,707
8.0% Senior Notes due 2018	765,000	750,000	762,849	750,000
8.75% Senior Notes due 2020(2)	475,875	443,568	472,968	443,057
7.5% Senior Notes due 2021	909,000	900,000		

(1) Carrying value is net of $10,921 and $12,793 discount at December 31, 2011 and 2010, respectively.

(2) Carrying value is net of $6,432 and $6,943 discount at December 31, 2011 and 2010, respectively.

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The carrying values of the Company s senior credit facility and remaining fixed rate debt instruments approximate fair value based on current 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 8.625% Senior Notes due 2015 (the 8.625% Senior Notes) and the issuance of the 7.5% Senior Notes due 2021 (the 7.5% Senior Notes), both of which occurred during 2011.

5. Accounts Receivable

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

	December 31,	
	2011	**2010**
Oil and natural gas sales	$ 134,491	$ 104,587
Oil and natural gas services	18,798	14,015
Joint interest billing	49,688	25,200
Production tax credits	3,331	
Related party	1,645	1,702
Other	2,289	2,117
	210,242	147,621
Less: allowance for doubtful accounts	(3,906)	(1,503)
Total accounts receivable, net	$ 206,336	$ 146,118

The following table presents the balance and activity in the allowance for doubtful accounts for the years ended December 31, 2011, 2010 and 2009 (in thousands):

	Year Ended December 31,		
	2011	**2010**	**2009**
Allowance for doubtful accounts, January 1	$ 1,503	$ 3,590	$ 3,874
Additions charged to costs and expenses	2,511	129	214
Deductions(1)	(108)	(2,216)	(498)
Allowance for doubtful accounts, December 31	$ 3,906	$ 1,503	$ 3,590

(1) Deductions represent write-off of receivables.

During 2008, the Company established an allowance in the amount of $1.5 million for all amounts due from SemGroup, L.P and certain of its subsidiaries (collectively, SemGroup) after SemGroup filed for bankruptcy in July 2008. During 2010, the Company received approximately $0.7 million from SemGroup, 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.

6. Other Current Assets

Other current assets consist of the following (in thousands):

	December 31,	
	2011	**2010**

Prepaid insurance	$ 7,797	$ 7,840
Prepaid drilling	2,745	1,826
Prepaid fees	1,897	2,162
Deposits	283	1,326
Other	4,132	1,482
Total other current assets	$ 16,854	$ 14,636

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7. Property, Plant and Equipment

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

	December 31, 2011	December 31, 2010
Oil and natural gas properties		
Proved	$ 8,969,296	$ 8,159,924
Unproved	689,393	547,953
Total oil and natural gas properties	9,658,689	8,707,877
Less accumulated depreciation, depletion and impairment(1)	(4,791,534)	(4,483,736)
Net oil and natural gas properties capitalized costs	4,867,155	4,224,141
Land	14,196	14,418
Non oil and natural gas equipment(2)	668,391	666,233
Buildings and structures	133,147	89,813
Total	815,734	770,464
Less accumulated depreciation and amortization	(293,465)	(260,740)
Net capitalized costs	522,269	509,724
Total property, plant and equipment	$ 5,389,424	$ 4,733,865

(1) Includes cumulative full cost ceiling limitation impairment charges of $3,548.3 million at both December 31, 2011 and 2010. See Note 8 for further discussion of impairment charges. There were no full cost ceiling impairments during the years ended December 31, 2011 and 2010.

(2) Includes cumulative capitalized interest of approximately $6.7 million and $4.7 million at December 31, 2011 and 2010, respectively.

The average rates used for depreciation and depletion of oil and natural gas properties were $13.97 per Boe in 2011, $13.70 per Boe in 2010 and $10.08 per Boe in 2009.

Costs Excluded from Amortization

Costs associated with unproved properties of $689.4 million as of December 31, 2011 were excluded from amounts subject to amortization. The following table summarizes the costs, by year incurred, related to unproved properties, including pipe inventory and the current loss estimate on construction of the Century Plant, which have been excluded from oil and natural gas properties being amortized at December 31, 2011 (in thousands):

		Year Cost Incurred			
	Total	2011	2010	2009	2008 and Prior
Property acquisition	$ 682,532	$ 228,400	$ 292,522	$ 32,254	$ 129,356
Exploration(1)	71,595	49,680	7,476	7,376	7,063
Development(2)	166,586	61,586	105,000		
Total costs incurred	$ 920,713	$ 339,666	$ 404,998	$ 39,630	$ 136,419

(1) Includes $64.7 million of pipe inventory with $46.1 million in 2011, $6.2 million in 2010, $5.3 million in 2009 and $7.1 million in 2008.

(2) Includes estimated losses of $25.0 million during 2011 and $105.0 million during 2010 currently identified on the construction of the Century Plant, which will become subject to amortization when the Century Plant has been placed into its intended use. See Note 12 for further discussion of the Century Plant.

The Company expects to complete the majority of the evaluation activities within six 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.

8. Impairment

Full Cost Ceiling Limitation. During the first quarter and the fourth quarter of 2009, the Company reduced the carrying value of its oil and natural gas properties by $1,304.4 million and $388.9 million, respectively, due to a full cost ceiling limitation. As a result of the Company s full valuation allowance on its net deferred tax asset, there was no tax effect on the full cost ceiling impairments taken in 2009. There were no full cost ceiling impairments during the years ended December 31, 2011 or 2010.

Other Property, Plant and Equipment. The Company recorded a $2.8 million impairment in 2011 on certain natural gas compressors due to the determination that their future use was limited. The Company recorded a $10.0 million impairment in the fourth quarter of 2009 on its spare parts inventory due to a decline in market value. The inventory was classified as other property, plant and equipment due to the Company s intent to place the parts into service in the future. Also in the fourth quarter of 2009, the Company recorded a $3.9 million impairment on three buildings located on its downtown Oklahoma City campus as management determined these buildings were of no use or value to the Company. There was no such impairment recorded during 2010.

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. Purchase price adjustments of ($5.4) million and $1.0 million recorded in 2010 and 2011, respectively, resulted in a net decrease to goodwill. Goodwill recorded in the Arena Acquisition is primarily attributable to operational and cost synergies expected to be realized from the acquisition by using the Company s current presence in the Permian Basin, its Fort Stockton, Texas service base and its existing rig ownership to efficiently increase its drilling and oil production from Arena assets acquired in the Central Basin Platform, as these assets have a proven production history. See Note 2 for additional discussion of the Arena Acquisition.

The Company s first annual evaluation of goodwill was completed during the third quarter of 2011. The Company assigned the goodwill related to the Arena Acquisition to its exploration and production segment, which is the reporting unit for impairment testing purposes. Under the discounted cash flow approach, the reporting unit s anticipated future cash flows, primarily based on projected oil and natural gas revenues, operating expenses and capital expenditures, were discounted using a weighted average cost of capital rate to estimate the fair value for the reporting unit. As the reporting unit s anticipated future cash flows were greater than the reporting unit s carrying value, no impairment loss was recognized. The Company monitors potential impairment indicators throughout the year. As of December 31, 2011, no such indicators were noted.

10. Other Assets

Other assets consist of the following (in thousands):

	December 31,	
	2011	**2010**
Debt issuance costs, net of amortization	$ 51,724	$ 50,637
Development advance	16,777	
Lease broker advances	13,086	
Production tax credit receivable	7,665	1,436
Investments	7,138	4,826
Other	2,232	2,852
Total other assets	$ 98,622	$ 59,751

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11. Accounts Payable and Accrued Expenses

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

	December 31,	
	2011	2010
Accounts payable	$ 313,901	$ 241,092
Production payable	59,825	34,293
Accrued interest	53,388	47,453
Drilling advances	36,637	1,734
Payroll and benefits	26,402	29,187
Convertible perpetual preferred stock dividends	16,572	17,363
Conoco settlement agreement current		5,000
Related party	59	800
Total accounts payable and accrued expenses	$ 506,784	$ 376,922

12. Century Plant Contract

The Company is constructing the Century Plant, a CO_2 treatment plant in Pecos County, Texas (the Century Plant), and associated compression and pipeline facilities pursuant to an agreement with Occidental Petroleum Corporation (Occidental). Under the terms of the agreement, the Company will construct the Century Plant and Occidental will pay the Company a minimum of 100% of the contract price, or $800.0 million, plus any subsequently agreed-upon revisions, through periodic cost reimbursements based upon the percentage of the project completed by the Company. The Company expects to complete the Century Plant in two phases. Upon completion of each phase of the Century Plant, Occidental will take ownership of the related assets and will operate the Century Plant for the purpose of separating and removing CO_2 from delivered natural gas. Phase I is in the commissioning process with completion and transfer of title to Occidental expected in early 2012, and Phase II is under construction and expected to be completed in 2012. The Company accounts for construction of the Century Plant using the completed-contract method, under which contract revenues and costs are recognized when work under both phases of the contract is completed and assets have been transferred to Occidental. In the interim, costs incurred on and billings related to contracts in process are accumulated on the balance sheet. Contract gains or losses will be recorded, as development costs within the Company s oil and natural gas properties as part of the full cost pool, when it is determined that a loss will be incurred. Contract gains, if any, are recorded at the end of the project. The Company has recorded an addition of $130.0 million ($105.0 million in 2010 and $25.0 million in 2011) to its oil and natural gas properties for the estimated loss identified based on current projections of the costs to be incurred in excess of contract amounts. Billings and estimated contract loss in excess of costs incurred of $43.3 million and $31.5 million at December 31, 2011 and 2010, respectively, are reported as current liabilities 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 will be required to deliver certain minimum CO_2 volumes annually once Occidental takes title, and will have to compensate Occidental to the extent such requirements are not met. See Note 16 for additional discussion of this volume requirement. The Company will retain all methane gas from the natural gas it delivers to the Century Plant.

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13. Long-Term Debt

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

	December 31, 2011	December 31, 2010
Senior credit facility	$	$ 340,000
Other notes payable		
Drilling rig fleet and related oil field services equipment		6,302
Mortgage	16,029	17,020
Senior Floating Rate Notes due 2014	350,000	350,000
8.625% Senior Notes due 2015		650,000
9.875% Senior Notes due 2016, net of $10,921 and $12,793 discount, respectively	354,579	352,707
8.0% Senior Notes due 2018	750,000	750,000
8.75% Senior Notes due 2020, net of $6,432 and $6,943 discount, respectively	443,568	443,057
7.5% Senior Notes due 2021	900,000	
Total debt	2,814,176	2,909,086
Less: Current maturities of long-term debt	1,051	7,293
Long-term debt	$ 2,813,125	$ 2,901,793

Senior Credit Facility. The senior credit facility is available to be drawn on subject to limitations based on its terms and certain financial covenants, as described below. The senior credit facility matures on April 15, 2014, unless the Company s Senior Floating Rate Notes due 2014 (the Senior Floating Rate Notes) have not been refinanced by December 31, 2013, in which case the senior credit facility will mature on January 31, 2014.

On February 23, 2011, the senior credit facility was amended to, among other things, (a) exclude from the calculation of Consolidated Net Income the net income (loss) of a Royalty Trust, except to the extent of cash distributions received by the Company, (b) establish that an investment in a Royalty Trust and dispositions to, and of interests in, Royalty Trusts are permitted, (c) clarify that a Royalty Trust is not a Subsidiary, (d) allow the Company to net against its calculation of Consolidated Funded Indebtedness cash balances exceeding $10.0 million in the event no loans are outstanding under the senior credit facility at that time and (e) establish that, for any fiscal quarter ending prior to March 31, 2012, if the ratio of the Company s secured indebtedness to EBITDA is less than 1.5:1.0, then compliance with the Company s Consolidated Leverage Ratio covenant is not required. Terms capitalized in the preceding sentence have the meaning given to them in the senior credit facility agreement, as amended.

On April 20, 2011, the senior credit facility was amended to permit the Company to pay cash dividends on its 7.0% convertible perpetual preferred stock. On December 22, 2011, the senior credit facility was further amended to establish that, for any fiscal quarter ending prior to March 31, 2013, if the ratio of the Company s secured indebtedness to EBITDA is less than 1.5:1.0, then compliance with the Company s Consolidated Leverage Ratio covenant is not required. Terms capitalized in the preceding sentence have the meaning given to them in the senior credit facility agreement, as amended.

As of December 31, 2011, the senior credit facility contained financial covenants, including maintaining agreed levels for the (i) ratio of total funded debt to EBITDA, which may not exceed 4.5:1.0 at each quarter end, calculated using the last four completed fiscal quarters, unless, for any quarter ending prior to March 31, 2013, the ratio of the Company s secured indebtedness to EBITDA is less than 1.5:1.0, calculated using the last four completed fiscal quarters, (ii) ratio of current assets to current liabilities, which must be at least 1.0:1.0 at each quarter end (in the current ratio calculation (as defined in the senior credit facility), 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) and (iii) ratio of the Company s secured indebtedness to EBITDA, which may not exceed 2.0:1.0 at each quarter end, calculated using the last four completed fiscal quarters. As of and during the year ended December 31, 2011, the Company was in compliance with all applicable financial covenants under the senior credit facility.

Additionally, 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.

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 each of the Company s material present and future subsidiaries; all intercompany debt of the Company; and substantially all of the Company s assets, including proved oil and natural gas reserves representing at least 80% 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.

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 2.00% and 3.00% 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 1.00% and 2.00% 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. The average annual interest rate paid on amounts outstanding under the senior credit facility was 2.69%, 2.70% and 2.33% for the years ended December 31, 2011, 2010 and 2009, respectively.

Borrowings under the senior credit facility may not exceed the lower of the borrowing base or the committed amount. On March 15, 2011, the borrowing base was reduced from $850.0 million to $790.0 million as a result of the issuance of the 7.5% Senior Notes, discussed below. The Company s borrowing base is redetermined in April and October of each year. At both the April and October 2011 redeterminations, the borrowing base remained unchanged at $790.0 million. 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 2011, additional costs of approximately $0.9 million were incurred. These costs have been deferred, are included in other assets in the accompanying consolidated balance sheet and are being amortized to interest expense over the term of the senior credit facility.

At December 31, 2011, the Company had no amount outstanding under the senior credit facility and $28.5 million in outstanding letters of credit, which affect the availability under the senior credit facility on a dollar-for-dollar basis.

Other Notes Payable. The Company financed a portion of its drilling rig fleet and related oil field services equipment through the issuance of notes secured by such equipment. In March 2011, the Company paid the outstanding $4.3 million principal balance on these notes.

The debt incurred to purchase the downtown Oklahoma City property that serves as the Company s corporate headquarters is fully secured by a mortgage on one of the buildings located on the property. The note underlying the mortgage bears interest at 6.08% annually and matures on November 15, 2022. Payments of principal and interest in the amount of approximately $0.5 million are due on a quarterly basis through the maturity date.

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Senior Floating Rate Notes Due 2014. The Company s Senior Floating Rate Notes were issued in May 2008. The Senior Floating Rate Notes are jointly and severally guaranteed unconditionally, in full, on an unsecured basis by certain of the Company s wholly owned subsidiaries and are freely tradable. See Note 24 for condensed financial information of the subsidiary guarantors.

The Senior Floating Rate Notes bear interest at LIBOR plus 3.625%. Interest is payable quarterly with the principal due on April 1, 2014. The average interest rate paid on the outstanding Senior Floating Rate Notes was 3.93%, 3.97% and 4.57% for the years ended December 31, 2011, 2010 and 2009, respectively, without consideration of the interest rate swap discussed below. The Company may redeem, at specified redemption prices, some or all of the Senior Floating Rate Notes at any time.

As of December 31, 2011, the Company had a $350.0 million notional interest rate swap agreement to effectively fix the variable interest rate on the Senior Floating Rate Notes to a fixed annual rate of 6.69% through April 1, 2013. This swap has not been designated as a hedge.

The $9.4 million of debt issuance costs associated with the Senior Floating Rate Notes is included in other assets in the accompanying consolidated balance sheets and is being amortized to interest expense over the term of the notes.

8.625% Senior Notes Due 2015. The Company s 8.625% Senior Notes were issued in May 2008. On March 1, 2011, the Company announced a cash tender offer to purchase any and all of the outstanding $650.0 million aggregate principal amount of its 8.625% Senior Notes for total consideration of $1,046.88 per $1,000 principal amount of such notes tendered by March 14, 2011. Holders tendering after March 14, 2011 were eligible to receive $1,016.88 per $1,000 principal amount of notes tendered. The Company purchased approximately 94.5%, or $614.2 million, of the aggregate principal amount of its 8.625% Senior Notes pursuant to the tender offer, which expired on March 28, 2011. On April 1, 2011, the Company redeemed the remaining outstanding $35.8 million aggregate principal amount of its 8.625% Senior Notes for $1,043.13 per $1,000 principal amount outstanding, plus accrued interest. 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 statement of operations for the year ended December 31, 2011.

9.875% Senior Notes Due 2016. The Company s unsecured 9.875% Senior Notes due 2016 (the 9.875% Senior Notes) were issued in May 2009 and bear interest at a fixed rate of 9.875% per annum, payable semi-annually, with the principal due on May 15, 2016. The 9.875% Senior Notes were issued at a discount, which is amortized into interest expense over the term of the notes. The 9.875% Senior 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 and are freely tradable.

Debt issuance costs of $7.9 million incurred in connection with the offering of the 9.875% Senior Notes are included in other assets in the accompanying consolidated balance sheets and are being amortized to interest expense over the term of the notes.

8.0% Senior Notes Due 2018. The Company s unsecured 8.0% Senior Notes due 2018 (the 8.0% Senior Notes) were issued in May 2008 and bear interest at a fixed rate of 8.0% per annum, payable semi-annually, with the principal due on June 1, 2018. The 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 and are freely tradable.

The Company incurred $16.0 million of debt issuance costs in connection with the offering of the 8.0% Senior Notes. 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 notes.

8.75% Senior Notes Due 2020. The Company s unsecured 8.75% Senior Notes due 2020 (the 8.75% Senior Notes) were issued in December 2009 and bear interest at a fixed rate of 8.75% per annum, payable semi-annually, with the principal due on January 15, 2020. The 8.75% Senior Notes were issued at a discount which is being amortized to interest expense over the term of the notes. The 8.75% Senior 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 and are freely tradable. See Note 24 for condensed financial information of the subsidiary guarantors.

Debt issuance costs of $9.7 million incurred in connection with the offering of and subsequent registered exchange of the 8.75% Senior Notes are included in other assets in the accompanying consolidated balance sheets and are being amortized to interest expense over the term of the notes.

7.5% Senior Notes Due 2021. In March 2011, the Company issued $900.0 million of unsecured 7.5% Senior Notes to qualified institutional buyers eligible under Rule 144A of the Securities Act of 1933, as amended (the Securities Act) and to persons outside the United States under Regulation S under the Securities Act. Net proceeds from the offering were approximately $880.6 million after deducting offering expenses, and were used to fund the tender offer for the 8.625% Senior Notes, including any accrued and unpaid interest, the redemption of the 8.625% Senior Notes that remained outstanding following the conclusion of the tender offer, including accrued and unpaid interest (each as described above) and to repay borrowings under the Company s senior credit facility. The 7.5% Senior Notes bear interest at a fixed rate of 7.5% per annum, payable semi-annually, with the principal due on March 15, 2021. Prior to March 15, 2016, the 7.5% Senior Notes are redeemable, in whole or in part, at a specified redemption price plus accrued and unpaid interest. On or after March 15, 2016, the 7.5% Senior Notes are redeemable, in whole or in part, prior to their maturity at other various specified redemption prices. The notes 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.

In November 2011, pursuant to an exchange offer, the Company replaced a substantial majority of the 7.5% Senior Notes, which were issued under Rule 144A and Regulation S under the Securities Act, with 7.5% Senior Notes registered under the Securities Act. The exchange offer did not result in the incurrence of any additional indebtedness.

Debt issuance costs of $19.4 million incurred in connection with the offering and subsequent exchange of the 7.5% Senior Notes are included in other assets in the accompanying consolidated balance sheets and are being amortized to interest expense over the term of the notes.

Indentures. The indentures governing the Company s senior notes contain 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, 2011, the Company was in compliance with all of the covenants contained in the indentures governing the senior notes.

Maturities of Long-Term Debt. Aggregate maturities of long-term debt, excluding discounts, during the next five years are as follows (in thousands):

Years ending December 31	
2012	$ 1,051
2013	1,120
2014	351,191
2015	1,266
2016	366,844
Thereafter	2,110,057
Total debt	$ 2,831,529

14. Derivatives

None of the Company s derivative contracts has been designated as a hedge. 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 the 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.

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 projected oil and natural gas sales. Additionally, the Company uses derivative contracts to manage commodity price risk associated with diesel fuel used in its operations. None of the Company s derivative contracts may be terminated early as a result of a party to the contract having its credit rating downgraded. At December 31, 2011, 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	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.
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 natural gas from a specified delivery point.

Interest Rate Swaps. The Company is exposed 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 the Company s interest obligations on these instruments are periodically redetermined based on prevailing market interest rates, primarily LIBOR and the federal funds rate.

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The Company has an interest rate swap agreement that effectively converts the variable interest rate on its Senior Floating Rate Notes to a fixed rate through April 1, 2013. See Note 13 for further discussion of the Company s interest rate swap.

Royalty Trust Derivatives Agreements. In April 2011, the Company entered into a derivatives agreement with the Mississippian Trust I, effective April 1, 2011. The agreement provides the Mississippian Trust I with the economic effect of certain oil and natural gas derivative contracts previously 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. Under this arrangement, the Company will pay the Mississippian Trust I amounts it receives from its counterparties in accordance with the underlying contracts, and the Mississippian Trust I will pay the Company any amounts that the Company is required to pay its counterparties under such contracts.

In August 2011, the Company entered into a derivatives agreement with the Permian Trust, effective August 1, 2011. The agreement provides the Permian Trust with the economic effect of certain oil derivative contacts previously entered into by the Company with third parties. The underlying commodity derivative contracts cover volumes of oil production through March 31, 2015. Under this arrangement, the Company will pay the Permian Trust amounts it receives from its counterparty in accordance with the underlying contracts, and the Permian Trust will pay the Company any amounts that the Company is required to pay such counterparty. Substantially concurrent with the execution of the derivatives agreement, the Company novated certain of the derivatives contracts underlying the derivatives agreement to the Permian Trust. As a party to these contracts, the Permian Trust will receive payment directly from the counterparty, and be required to pay any amounts owed directly to the counterparty. To secure the Permian Trust s obligations under these novated contracts, the Permian Trust has given the counterparty a lien on its royalty interests in certain oil and natural gas properties. Under the derivatives agreement, as development wells are drilled for the benefit of the Permian Trust, the Company will have the right, under certain circumstances, to assign or novate to the Permian Trust additional derivative contracts.

All contracts underlying the derivatives agreements with the Mississippian Trust I and Permian Trust, including those novated to the Permian Trust, have been included in the Company s consolidated derivative disclosures. See Note 3 for further discussion of the Mississippian Trust I and the Permian Trust.

Fair Value of Derivatives. The following table presents the fair value of the Company s derivative contracts as of December 31, 2011 and 2010 on a gross basis without regard to same-counterparty netting (in thousands):

Type of Contract	Balance Sheet Classification	December 31, 2011	December 31, 2010
Derivative assets			
Oil price swaps	Derivative contracts-current	$ 6,095	$
Natural gas price swaps	Derivative contracts-current	6,585	8,500
Natural gas collars	Derivative contracts-current	313	
Diesel price swaps	Derivative contracts-current	397	
Oil price swaps	Derivative contracts-noncurrent	48,718	
Natural gas price swaps	Derivative contracts-noncurrent		3,518
Natural gas collars	Derivative contracts-noncurrent	1,035	
Derivative liabilities			
Oil price swaps	Derivative contracts-current	(116,243)	(63,123)
Natural gas price swaps	Derivative contracts-current		(640)
Natural gas basis swaps	Derivative contracts-current		(34,112)
Diesel price swaps	Derivative contracts-current	(41)	
Interest rate swaps	Derivative contracts-current	(8,475)	(9,007)
Oil price swaps	Derivative contracts-noncurrent	(66,451)	(84,055)
Natural gas price swaps	Derivative contracts-noncurrent		(802)
Natural gas basis swaps	Derivative contracts-noncurrent	(4,609)	(34,908)
Natural gas collars	Derivative contracts-noncurrent		(238)
Interest rate swaps	Derivative contracts-noncurrent	(1,973)	(7,687)
Total net derivative contracts		$ (134,649)	$ (222,554)

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Refer to Note 4 for additional discussion on the fair value measurement of the Company s derivative contracts.

The following table summarizes the effect of the Company s derivative contracts on the accompanying consolidated statements of operations for the years ended December 31, 2011, 2010 and 2009 (in thousands):

Type of Contract	Location of (Gain) Loss Recognized in Income	Amount of (Gain) Loss Recognized in Income 2011	2010	2009
Commodity derivatives	(Gain) loss on derivative contracts	$ (44,075)	$ 50,872	$ (147,527)
Interest rate swaps	Interest expense	3,168	16,540	5,783
Total		$ (40,907)	$ 67,412	$ (141,744)

The following tables summarize the cash settlements and valuation gains and losses on the Company s commodity derivative contracts and interest rate swaps for the years ended December 31, 2011, 2010 and 2009 (in thousands):

Commodity Derivatives	Year Ended December 31, 2011	2010	2009
Realized loss (gain)(1)	$ 50,713	$ (224,337)	$ (348,022)
Unrealized (gain) loss	(94,788)	275,209	200,495
(Gain) loss on commodity derivative contracts	$ (44,075)	$ 50,872	$ (147,527)

Interest Rate Swaps	Year Ended December 31, 2011	2010	2009
Realized loss	$ 9,414	$ 8,145	$ 6,229
Unrealized (gain) loss	(6,246)	8,395	(446)
Loss on interest rate swaps	$ 3,168	$ 16,540	$5,783

(1) Includes $48.1 million net realized gains ($111.0 million realized gains and $62.9 million realized losses) for the year ended December 31, 2011 related to settlements of commodity derivative contracts with contractual maturities after the quarterly period in which they were settled (out-of-period settlements). Includes $114.4 million of realized gains for the year ended December 31, 2010, related to out-of-period settlements. There were no out-of-period settlements during 2009.

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At December 31, 2011, the Company s open commodity derivative contracts consisted of the following:

Oil Price Swaps(1)

Contract Period	Notional (MBbl)	Weighted Avg. Fixed Price
January 2012 March 2012(2)	2,902	$ 89.78
April 2012 June 2012(2)	2,993	$ 89.64
July 2012 September 2012(2)	3,056	$ 89.60
October 2012 December 2012(2)	3,118	$ 89.52
January 2013 March 2013	2,910	$ 92.52
April 2013 June 2013	2,943	$ 92.52
July 2013 September 2013	2,975	$ 92.52
October 2013 December 2013	2,975	$ 92.52
January 2014 March 2014	2,211	$ 93.82
April 2014 June 2014	2,236	$ 93.82
July 2014 September 2014	2,260	$ 93.82
October 2014 December 2014	2,260	$ 93.82
January 2015 March 2015	1,159	$ 95.77
April 2015 June 2015	865	$ 93.95
July 2015 September 2015	874	$ 93.95
October 2015 December 2015	874	$ 93.95

Natural Gas Price Swaps

Contract Period	Notional (MMBtu)	Weighted Avg. Fixed Price
January 2012 March 2012	1,820	$ 4.90
April 2012 June 2012	1,820	$ 4.90

Natural Gas Basis Swaps

Contract Period	Notional (MMBtu)	Weighted Avg. Fixed Price
January 2013 March 2013	3,600	$ (0.46)
April 2013 June 2013	3,640	$ (0.46)
July 2013 September 2013	3,680	$ (0.46)
October 2013 December 2013	3,680	$ (0.46)

Natural Gas Collars

Contract Period	Notional (MMBtu)	Collar Range
July 2012 September 2012	201	$ 4.00 - 6.20
October 2012 December 2012	201	$ 4.00 - 6.20
January 2013 March 2013	212	$ 4.00 - 7.15
April 2013 June 2013	214	$ 4.00 - 7.15
July 2013 September 2013	216	$ 4.00 - 7.15
October 2013 December 2013	216	$ 4.00 - 7.15
January 2014 March 2014	231	$ 4.00 - 7.78

April 2014	June 2014	234	$ 4.00 - 7.78
July 2014	September 2014	236	$ 4.00 - 7.78
October 2014	December 2014	236	$ 4.00 - 7.78
January 2015	March 2015	249	$ 4.00 - 8.55
April 2015	June 2015	252	$ 4.00 - 8.55
July 2015	September 2015	255	$ 4.00 - 8.55
October 2015	December 2015	255	$ 4.00 - 8.55

Diesel Price Swaps

Contract Period	Notional (Thousands of Gallons)	Weighted Avg. Fixed Price
January 2012 March 2012	1,512	$ 2.86
April 2012 June 2012	1,512	$ 2.83
July 2012 September 2012	1,512	$ 2.83
October 2012 December 2012	1,512	$ 2.81

(1) Includes derivative contracts novated to the Permian Trust. See Note 3 for a listing of such contracts.
(2) Includes 7,885 MBbl covered under contracts amended in January 2012. Resulting amended maturities are 3,864 MBbl in 2014 and 3,864 MBbl in 2015.

15. Asset Retirement Obligation

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

	2011	2010	2009
Asset retirement obligation, January 1	$ 119,877	$ 111,137	$ 84,772
Liability incurred upon acquiring and drilling wells	5,716	17,347	14,537
Revisions in estimated cash flows	7,574	(17,017)	10,831
Liability settled or disposed in current period	(14,419)	(1,011)	(6,111)
Accretion expense	9,368	9,421	7,108
Asset retirement obligation, December 31	128,116	119,877	111,137
Less: current portion	(32,906)	(25,360)	(2,553)
Asset retirement obligation, net of current	$ 95,210	$ 94,517	$ 108,584

Asset retirement obligation 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 anticipated plugging and abandonment in 2011. For the year ended December 31, 2009, revisions in estimated cash flows were primarily due to shortening reserve lives based on lower oil and natural gas prices used to determine reserves relative to respective beginning of year prices. Also, due to hurricane damage, certain non-operated offshore platforms were plugged and abandoned during 2009 in advance of anticipated timelines.

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, 2011, 2010 and 2009 was approximately $1.5 million, $2.6 million and $3.2 million, respectively.

Future minimum lease payments under noncancelable operating leases (with initial lease terms exceeding one year) as of December 31, 2011 were as follows (in thousands):

Years ending December 31

2012	$ 597
2013	475
2014	317
2015	140
	$ 1,529

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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, 2011 were $30.2 million for 2012 and $12.9 million for 2013.

Hydraulic Services Agreements. The Company has third-party hydraulic well fracturing services agreements through 2013 that contain certain termination fees. At December 31, 2011, these termination fees were $39.0 million.

Oil and Natural Gas Transportation and Throughput Agreements. The Company has subscribed firm gas transportation service under two transportation service agreements, the terms of which continue through 2012 on the Oasis Pipeline and through 2018 on the Midcontinent Express Pipeline. These commitments are not recorded in the consolidated balance sheets. Under the terms of each agreement, the Company is obligated to pay a demand charge and in exchange, obtains the right to flow natural gas production through these pipelines 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, 2011 were as follows (in thousands):

Years ending December 31	
2012	$ 31,723
2013	26,061
2014	17,976
2015	11,315
2016	11,346
Thereafter	30,163
	$ 128,584

Natural Gas Gathering Agreement. In conjunction with the sale of the gathering and compression assets located in the Piñon Field in west Texas, the Company entered into a gas gathering agreement. Under the gas gathering agreement, the Company has dedicated its west Texas acreage for priority gathering services through June 30, 2029 and the Company will pay a fee that was negotiated at arms length 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, 2011 (in thousands).

Years ending December 31	
2012	$ 42,814
2013	42,634
2014	42,360
2015	42,153
2016	42,091
Thereafter	183,587
	$ 395,639

CO_2 Purchase Commitment. The Company has a commitment in place to purchase CO_2 for use in certain tertiary oil recovery operations. The price paid for CO_2 under this agreement is dependent on certain New York Mercantile Exchange commodity prices. The amount below represents the committed CO2 volumes at the base rate. The table below presents the contractual obligations under this agreement as of December 31, 2011 (in thousands).

Years ending December 31	
2012	$ 12,444
2013	10,336

$ 22,780

Treating Agreement. In conjunction with the Century Plant construction agreement, the Company entered into a 30-year treating agreement with Occidental for CO_2 to be removed from the Company s delivered production volumes. The Company is required to deliver a total of 3,289 Bcf of CO_2 volumes during the agreement period. If the Company does not meet the CO_2 volume requirements, the Company will have to pay a fee for any volume shortfalls. Based upon current natural gas production levels, the Company expects to accrue between approximately $17.0 million and $21.0 million during the year ending December 31, 2012 for amounts related to the Company s shortfall in meeting its delivery obligations based on the projected completion date of Phase I. 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.

Sponsorship Agreement. The Company has two years remaining under a five-year sponsorship agreement under which it pays approximately $3.3 million per year for advertising and promotional activities related to the Oklahoma City Thunder, a National Basketball Association team playing in Oklahoma City, where the Company is headquartered. Additionally, the Company has two years remaining under a four year agreement to license a suite at the arena where the Oklahoma City Thunder plays its home games for $0.2 million per year. See Note 21 for additional information.

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 plant fire, 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, has tendered indemnity requests to GRLP, of which the Company is a 50% owner. GRLP has not accepted or acknowledged any responsibility to indemnify Southern Union. 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. An estimate of reasonably possible losses associated with these claims is approximately $12.3 million. As the loss is not probable, the Company has not established any reserves relating to these claims.

On February 14, 2011, Aspen Pipeline, II, L.P. (Aspen) filed a complaint in the District Court of Harris County, Texas, against Arena Resources, Inc. and SandRidge Energy, Inc. 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. The Company intends to defend this lawsuit vigorously and believes the plaintiff s claims are without merit. This case is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this claim, 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 claim.

On April 5, 2011, Wesley West Minerals, Ltd. and Longfellow Ranch Partners, LP filed suit against SandRidge Energy, Inc. 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 unspecified actual damages, 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. The Company intends to defend this lawsuit vigorously. This case is in the early stages and, accordingly, an estimate of reasonably possible losses associated with these claims, 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 claims.

SandRidge acquired certain oil and natural gas leases in Loving County, Texas, from mineral owners in April 2010, which it subsequently sold to Energen Resources Corporation (Energen) in December 2010 for an allocated value of approximately $4.0 million. Subsequent to the acquisition by SandRidge of the leases and prior to their disposition to Energen, the mineral owners executed oil and natural gas leases conveying the same mineral estates to Cimarex Energy Co. (Cimarex). SandRidge has requested a declaratory judgment resolving all disputes between it and Cimarex regarding the validity of the leases insofar as they purport to cover the same mineral interests. In connection with that action, Cimarex has filed a third-party petition naming Energen as a third-party defendant, and is asserting quiet title and trespass to try title claims against Energen. Energen has tendered to SandRidge a demand for indemnity, and SandRidge has assumed Energen s defense and any potential loss suffered by it. An estimate of reasonably possible losses associated with the demand for indemnity is approximately $4.0 million. As the loss is not probable, the Company has not established any reserves relating to the demand.

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 SandRidge Energy, Inc., SandRidge Exploration and Production, LLC (SandRidge E&P) and certain directors and senior executive officers of SandRidge Energy, Inc. (collectively, the defendants) in the U.S. District Court for the District of Connecticut. The plaintiffs allege that the defendants made false and misleading statements to U.S. Drilling Capital Management LLC and 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. This case is in the early stages and, accordingly, an estimate of reasonably possible losses associated with this claim, 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 claim.

The Company is a defendant in lawsuits from time to time in the normal course of business. In management s opinion, the Company is not currently involved in any other legal proceedings which, individually or in the aggregate, could have a material effect on the financial condition, operations or cash flows of the Company.

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17. Equity

Preferred Stock

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

	December 31, 2011	December 31, 2010
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

The Company is authorized to issue 50,000,000 shares of preferred stock, $0.001 par value, of which 7,650,000 shares are designated as convertible perpetual preferred stock at December 31, 2011. All of the outstanding shares of the Company s convertible perpetual preferred stock were issued in private transactions and none of these shares is listed on a stock exchange. However, as of December 31, 2011, 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 based on an initial conversion price of $8.01, subject to adjustments upon the occurrence of certain events. 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. All dividend payments to date have been paid in cash. Approximately $22.5 million ($14.1 million paid and $8.4 million unpaid), $22.5 million ($14.1 million paid and $8.4 million unpaid), and $8.4 million in dividends (all unpaid) on the 8.5% convertible perpetual preferred stock have been included in the calculation of income available (loss applicable) to common stockholders and the Company s basic earnings per share calculation for the years ended December 31, 2011, 2010 and 2009, respectively, as presented in the accompanying consolidated statements of operations. 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. All dividend payments to date have been paid in cash. Approximately $12.0 million ($6.5 million paid and $5.5 million unpaid), $12.0 million ($6.0 million paid and $6.0 million unpaid) and $0.4 million in dividends (all unpaid) on the 6.0% convertible perpetual preferred stock have been included in the calculation of income available (loss applicable) to common stockholders and the Company s basic earnings per share calculation for the years ended December 31, 2011, 2010 and 2009, respectively, as presented in the accompanying consolidated statements of operations. 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 based on an initial conversion price of $10.86 and subject to customary adjustments in certain circumstances. After December 21, 2014, the Company may cause all outstanding shares of the 6.0% convertible preferred stock to convert automatically into shares of the Company s common stock at the then-prevailing conversion price 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 based on an initial conversion price of $7.76 per share. 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 beginning on May 15, 2011. All dividend payments to date have been paid in cash. Approximately $21.1 million ($18.5 million paid and $2.6 million unpaid) and $2.9 million in dividends (all unpaid) on the 7.0% convertible perpetual preferred stock have been included in the calculation of income available to common stockholders and the Company s basic earnings per share calculation for the years ended December 31, 2011 and 2010, respectively, as presented in the accompanying consolidated statements of operations. 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.

Common Stock

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

	December 31,	
	2011	**2010**
Shares authorized	800,000	800,000
Shares outstanding at end of period	411,953	406,360
Shares held in treasury	874	470

In April 2009, the Company completed a registered underwritten offering of 14,480,000 shares of its common stock, including 2,280,000 shares of common stock acquired by the underwriters from the Company to cover over-allotments. Net proceeds from the offering were approximately $107.6 million, after deducting offering expenses of approximately $2.4 million, and were used to repay a portion of the amount outstanding under the senior credit facility and for general corporate purposes.

In December 2009, the Company completed a registered underwritten public offering of 25,600,000 shares of its common stock, including 3,600,000 shares of common stock acquired by the underwriters from the Company to cover over-allotments. Net proceeds from the offering were approximately $217.2 million after deducting offering expenses of approximately $9.4 million. The net proceeds were used to fund the purchase of oil and natural gas properties from Forest and for general corporate purposes.

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. See Note 2 for further discussion regarding the Arena Acquisition.

In December 2010, the Company issued 1,788,909 shares of Company common stock (of which 491,950 shares were newly issued and 1,296,959 shares were issued from treasury stock) as part of the settlement of a dispute with certain working interest owners. The issuance of the 491,950 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.

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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 1,175,501 shares having a total value of $10.8 million, 845,608 shares having a total value of $6.3 million, and 167,009 shares having a total value of $1.5 million during the years ended December 31, 2011, 2010 and 2009, respectively. These shares were accounted for as treasury stock when withheld, and subsequently retired. In December 2010, the Company retired all shares currently held as treasury and any shares of common stock purchased into treasury in the future to satisfy tax withholding obligations related to the vesting of restricted stock awards that are forfeited under the Company s incentive compensation plans, excluding shares of Company common stock held as assets in a trust for the Company s non-qualified deferred compensation plan. 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.

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 1,788,909 shares of Company common stock. As noted above, 491,950 of such shares were newly issued and the remaining 1,296,959 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.

Any 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 and for purposes of voting at Company stockholder meetings, these shares are considered outstanding and have voting rights, which are exercised by the Company.

Equity Compensation

The Company awards restricted common stock under incentive compensation plans 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. All awards issued during and after 2006 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.

Equity compensation provided to employees directly involved in oil and natural gas exploration and development activities is capitalized to the Company s oil and natural gas properties. Equity compensation not capitalized is reflected in general and administrative expenses, production expenses, midstream and marketing expenses and drilling and services expenses in the consolidated statements of operations. For the years ended December 31, 2011, 2010 and 2009, the Company recognized equity compensation expense of $36.0 million, $37.7 million and $22.8 million, net of $7.6 million, $5.6 million and $4.3 million capitalized, respectively, related to restricted common stock.

Effective June 5, 2009, the Company adopted the SandRidge Energy, Inc. 2009 Incentive Plan (the 2009 Incentive Plan). Under the terms of the 2009 Incentive Plan, the Company may grant stock options, stock appreciation rights, shares of restricted stock, restricted stock units and other forms of awards based on the value (or increase in the value) of shares of the common stock of the Company for up to 22,500,000 shares of common stock. The 2009 Incentive Plan also permits cash incentive awards. Consistent with its other incentive plans, the Company intends for shares of restricted stock to be the primary form of awards granted under the 2009 Incentive Plan.

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Restricted stock activity for the years ended December 31, 2009, 2010 and 2011 was as follows (shares in thousands):

	Number of Shares	Weighted-Average Grant Date Fair Value
Unvested restricted shares outstanding at December 31, 2008	2,993	$ 30.71
Granted	3,531	$ 8.34
Vested	(800)	$ 29.43
Forfeited / Canceled	(402)	$ 20.97
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

(1) Excludes 743,119 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, 2011, 2010 and 2009, including stock awards assumed in the Arena Acquisition, was $30.2 million, $17.5 million and $6.9 million, respectively. As of December 31, 2011, there was approximately $92.5 million of unrecognized compensation cost related to unvested restricted stock awards, which is expected to be recognized over a weighted average period of 2.7 years. Under its existing incentive compensation plans, the Company had approximately 11,570,000 shares available for grant at December 31, 2011.

Noncontrolling Interest

Noncontrolling interests in the Company s subsidiaries and four VIEs of which the Company is the primary beneficiary (see Note 3), represent third-party ownership interests in the consolidated entity and are included as a component of equity in the consolidated balance sheet and consolidated statement 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 2011 annual 401(k) deferral limit for employees under age 50 was $16,500. Employees turning age 50 or over in 2011 could defer up to $22,000 in 2011. The Company makes matching contributions to the plan equal to 100% on the first 15% of employee deferred wages. All matching contributions are made with Company stock. For 2011, 2010 and 2009, the Company satisfied its matching obligations related to employee contributions with cash purchases of Company stock. For 2011, 2010 and 2009, retirement plan expense was approximately $7.4 million, $8.7 million and $7.4 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 gross earnings. For 2011, 2010 and 2009, employer contributions were approximately $3.1 million, $2.8 million and $2.5 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 deferred compensation in the plan.

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,		
	2011	2010	2009
Current			
Federal	$ 618	$ (732)	$ (4,413)
State	551	1,552	(4,303)
	1,169	820	(8,716)
Deferred			
Federal	(6,447)	(434,117)	
State	(539)	(13,383)	
	(6,986)	(447,500)	
Total benefit	(5,817)	(446,680)	(8,716)
Less: income tax provision attributable to noncontrolling interest	109	115	
Total benefit attributable to SandRidge Energy, Inc.	$ (5,926)	$ (446,795)	$ (8,716)

A reconciliation of the provision (benefit) for income taxes at the statutory federal tax rate to the Company s actual income tax benefit is as follows for the years ended December 31 (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Computed at federal statutory rate	$ 54,800	$ (88,085)	$ (623,717)
State taxes, net of federal benefit	5,231	1,659	(14,265)
Non-deductible expenses	6,395	5,507	1,905
Stock-based compensation	6,341	9,384	5,941
Net effects of consolidating the non-controlling interests tax provisions	(18,927)	(1,555)	(790)
Other	(2,845)	4,131	(19,098)
Change in valuation allowance	(51,631)	69,664	641,308
Valuation allowance release	(5,290)	(447,500)	
Total income tax benefit.	$ (5,926)	$ (446,795)	$ (8,716)

Deferred income taxes are provided to reflect the future tax consequences 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 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 the weight of all available evidence. As of December 31, 2008, the Company determined it was appropriate to record a full valuation allowance against its net deferred tax asset. In the second quarter of 2011, the Company completed its valuation of assets acquired and liabilities assumed related to the Arena Acquisition in order to finalize the purchase price allocation. In connection therewith, the Company adjusted the previously recorded net deferred tax liability associated with the Arena

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Acquisition by recording an additional net deferred tax liability of $7.0 million. The adjustment resulted in the Company releasing a corresponding portion of its previously recorded valuation allowance resulting in a deferred tax benefit. This release of valuation allowance is in addition to the $447.5 million released in 2010. The 2010 and 2011 partial releases of the valuation allowance were based on management s assessment that it is more likely than not that the Company will realize a benefit from more of its existing deferred tax assets as the Arena deferred tax liabilities are available to offset the reversal of the Company s deferred tax assets. The Company continued to have a full valuation allowance against its net deferred tax asset at December 31, 2011.

Significant components of the Company s deferred tax assets and liabilities are as follows (in thousands):

	December 31,	
	2011	**2010**
Deferred tax liabilities		
Investments(1)	$ 233,819	$ 3,540
Total deferred tax liabilities	233,819	3,540
Deferred tax assets		
Property, plant and equipment	289,148	251,106
Derivative contracts	39,268	71,767
Allowance for doubtful accounts	11,725	1,192
Net operating loss carryforwards	556,768	374,296
Litigation settlement		4,392
Compensation and benefits	14,053	12,799
Alternative minimum tax credits and other carryforwards	39,979	16,828
Asset retirement obligation	45,762	42,805
Other	2,721	4,052
Total deferred tax assets	999,424	779,237
Valuation allowance	(765,605)	(775,697)
Net deferred tax liability	$	$

(1) Includes the Company s deferred tax liability resulting from its investment in the Mississippian Trust I and the Permian Trust. See Note 3 for further discussion of the royalty trusts.

As of December 31, 2011, the Company had approximately $6.6 million of alternative minimum tax credits available that do not expire. In addition, the Company had approximately $1,492.6 million of federal net operating loss carryovers that expire during the years 2023 through 2031. Excess tax benefits of approximately $18.3 million associated with the vesting of restricted stock awards are included in the federal net operating loss carryovers, but will not be recognized as a tax benefit recorded to additional paid-in capital until realized.

IRC Section 382 addresses company ownership changes and specifically limits the utilization of certain deductions and other tax attributes on an annual basis following an ownership change. The Company experienced an ownership change within the meaning of IRC Section 382 on December 31, 2008. The ownership change subjected certain of the Company s tax attributes, including $298.4 million of federal net operating loss carryforwards, to the IRC Section 382 limitation. The Company experienced a subsequent ownership change within the meaning of IRC Section 382 on July 16, 2010 as a result of the Arena Acquisition. The subsequent ownership change resulted in a more restrictive limitation on certain of the Company s tax attributes than with the December 31, 2008 ownership change. The more restrictive limitation applies not only to the $298.4 million of federal net operating loss carryforwards and certain other tax attributes existing at December 31, 2008 but also to net operating losses of approximately $552.9 million and certain other tax attributes generated in periods

following the December 31, 2008 ownership change. The subsequent limitation could result in a material amount of existing loss carryforwards expiring unused. Arena also experienced an ownership change on July 16, 2010 as a result of its acquisition by the Company. This ownership change is expected to result in a limitation on Arena s net operating loss carryforwards available to the Company. None of the limitations discussed above resulted in a current federal tax liability at December 31, 2011 and 2010.

As of December 31, 2011 and 2010, respectively, the Company had a liability of approximately $1.8 million and $1.5 million, respectively, for unrecognized tax benefits. If recognized, approximately $1.1 million, net of federal tax expense, would be recorded as a reduction of income tax expense and would affect the effective tax rate.

Consistent with the Company s policy to record interest and penalties on income taxes as a component of the income tax provision, the Company has included $0.1 million of accrued gross interest with respect to unrecognized tax benefits in its consolidated statement of operations during each of the years ended December 31, 2011 and 2010. The Company had a corresponding accrued liability of $0.2 million and $0.1 million for interest and penalties relating to uncertain tax positions at December 31, 2011 and 2010, respectively.

The Company s only taxing jurisdiction is the United States (federal and state). The Company s tax years 2008 to present remain open for federal examination. Additionally, various tax years remain open beginning with tax year 2003 due to federal net operating loss carryforwards. The number of years open for state tax audits varies, depending on the state, but are generally from three to five years. Currently, several examinations are in progress. The Company does not anticipate that any federal or state audits will have a significant impact on the Company s results of operations or financial position. As a result of ongoing negotiations pertaining to the Company s current state audits, it is reasonably possible that the Company s gross unrecognized tax benefits balance may decrease within the next twelve months by approximately $1.5 million.

For the year ended December 31, 2011, income tax payments, net of refunds, were approximately $2.1 million, compared to income tax refunds, net of payments of $1.5 million, for the year ended December 31, 2010, and income tax payments, net of refunds, of $2.9 million for the year ended December 31, 2009.

20. Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed using the weighted average shares outstanding during the period, but also include the dilutive effect of awards of restricted stock, using the treasury stock method, and outstanding convertible preferred stock. Under the treasury stock method, the amount of unrecognized compensation expense related to unvested stock-based compensation grants are assumed to be used to repurchase shares. The following table summarizes the calculation of weighted average common shares outstanding used in the computation of diluted earnings per share, for the years ended December 31 (in thousands):

	2011	**2010**	**2009**
Weighted average basic common shares outstanding	398,851	291,869	175,005
Effect of dilutive securities			
Restricted stock	7,794	5,057	
Convertible preferred stock		18,423	
Weighted average diluted common and potential common shares outstanding	406,645	315,349	175,005

For the year ended December 31, 2009, restricted stock awards covering approximately 2.8 million shares were excluded from the computation of loss per share because their effect would have been antidilutive.

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In computing diluted earnings per share, the Company evaluated the if-converted method with respect to its outstanding 8.5% convertible perpetual preferred stock, 6.0% convertible perpetual preferred stock and 7.0% convertible perpetual preferred stock for the year ended December 31, 2011, and with respect to its outstanding 8.5% convertible perpetual preferred stock and 6.0% convertible perpetual preferred stock for the years ended December 31, 2010 and 2009. The 7.0% convertible perpetual preferred stock issued in November 2010 was not included in the evaluation of the if-converted method for the year ended December 31, 2010, as the shares were not convertible by the holders into shares of the Company s common stock until February 15, 2011. See Note 17 for discussion of the Company s convertible perpetual preferred stock. Under the if-converted method, the Company assumes the conversion of the preferred stock to common stock and determines if this is more dilutive than including the preferred stock dividends (paid and unpaid) in the computation of income available to common stockholders. For the year ended December 31, 2011, the Company determined the if-converted method was not more dilutive and included the 8.5%, 6.0% and 7.0% preferred stock dividends in the determination of income available to common stockholders. For the year ended December 31, 2010, the Company determined the if-converted method was more dilutive with respect to its 6.0% convertible perpetual preferred stock, but not more dilutive with respect to its 8.5% convertible perpetual preferred stock. As a result, the Company did not include the $12.0 million of 6.0% preferred stock dividends, but did include the 8.5% preferred stock dividends in the determination of income available to common stockholders. For the year ended December 31, 2009, the Company determined the if-converted method was not more dilutive and included the 8.5% and 6.0% preferred stock dividends in the determination of income available to common stockholders.

21. Related Party Transactions

The Company enters into transactions in the ordinary course of business with certain related parties. These transactions primarily consist of purchases related to drilling and completion activities, gas treating services and drilling equipment and sales of oil field services, equipment and natural gas. See Note 5 and Note 11 for accounts receivable and accounts payable, respectively, attributable to related party transactions. Following is a summary of significant sales and purchase transactions with such related parties for years ended December 31 (in thousands):

	2011	2010	2009
Sales to and reimbursements from related parties(1)	$ 21,539	$ 15,713	$ 7,304
Purchases of services from related parties	$ 217	$ 165	$ 21,745

(1) 2011 and 2010 amounts and the majority of 2009 amounts represent sales of natural gas to Southern Union, the Company s partner in GRLP.

Oklahoma City Thunder Agreements. The Company s Chairman and Chief Executive Officer owns a minority interest in a limited liability company that owns and operates the Oklahoma City Thunder, basketball team. The Company is party to a sponsorship agreement, through the 2013 season, whereby it pays approximately $3.3 million per year for advertising and promotional activities related to the Oklahoma City Thunder. Additionally, the Company entered into an agreement to license a suite at the arena where the Oklahoma City Thunder plays its home games. Under this four-year agreement, the Company pays an annual license fee of $0.2 million through 2013. Amounts related to these agreements are not included in the tables above. At December 31, 2011, the Company had no amounts due under these agreements. At December 31, 2010, the amount due under these agreements was $0.8 million.

22. Subsequent Events

Events occurring after December 31, 2011 were evaluated to ensure that any subsequent events that met the criteria for recognition and/or disclosure in this report have been included.

Sale of Working Interests. In January 2012, SandRidge sold to Repsol E&P USA Inc. (Repsol) an approximate 25% non-operated working interest, equal to approximately 250,000 net acres, in the

Mississippian formation in western Kansas, and an approximate 16% non-operated working interest, 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 for approximately $272.5 million. In addition, Repsol will pay for its working interest share of development costs and will fund a portion of SandRidge s development costs equal to 200% of Repsol s working interest for wells within an area of mutual interest, up to $750.0 million, which is expected to occur over a five-year period.

SandRidge Mississippian Trust II. On January 5, 2012, the Company and SandRidge Mississippian Trust II (the Mississippian Trust II), a newly formed Delaware statutory trust, filed registration statements with the Securities and Exchange Commission (SEC) for the proposed public offering of common units representing beneficial interests in the Mississippian Trust II. Prior to the closing of this offering, the Company intends to convey certain royalty interests to the Mississippian Trust II in exchange for the net proceeds from the offering and units, representing a beneficial interest in the Mississippian Trust II. The royalty interests to be conveyed to the Mississippian Trust II are in certain oil and natural gas properties leased by the Company in the Mississippian formation in northern Oklahoma and southern Kansas. There can be no assurance that the Company will complete this transaction, as it is subject to market conditions and other uncertainties, as well as completion of the SEC review process.

Dynamic Acquisition. On February 1, 2012, the Company entered into an agreement to acquire Dynamic Offshore Resources, LLC (Dynamic), an oil and natural gas exploration, development and production company with operations in the Gulf of Mexico for approximately $1.3 billion, comprised of approximately $680.0 million in cash and approximately 74 million shares of the Company s common stock. The acquisition, which is expected to close in the second quarter of 2012, is subject to customary closing conditions, including compliance with the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act. The Company has secured $725.0 million in committed financing for the acquisition that it may use to fund the cash portion of the acquisition.

Royalty Trust Distributions. On February 2, 2012, the Mississippian Trust I and the Permian Trust announced quarterly distributions for the three-month period ended December 31, 2011 of $22.1 million, or $0.79 per unit, and $29.1 million, or $0.55 per unit, respectively. Of these distribution amounts, $13.6 million and $19.1 million will be distributed to the third party trust unitholders in the Mississippian Trust I and the Permian Trust, respectively. The distributions are expected to occur on or before February 29, 2012 to holders of record as of the close of business on February 14, 2012.

Sale of Trust Units. On February 21, 2012, the Company sold approximately 1.6 million of its Mississippian Trust I common units in a transaction exempt from registration under Rule 144 under the Securities Act for proceeds of $52.3 million.

23. Business Segment Information

The Company has three business segments: exploration and production, drilling and oil field services and midstream gas 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. The drilling and oil field services segment is engaged in the contract drilling of oil and natural gas wells. The midstream gas services segment is engaged in the purchasing, gathering, treating and selling of natural gas. The All Other column in the tables below includes items not related to the Company s reportable segments, including the Company s CO_2 gathering and sales operations and corporate operations.

As further discussed in Note 24, SandRidge Energy, Inc., the parent company, contributed its oil and natural gas related assets and liabilities to one of its wholly owned subsidiaries effective as of May 1, 2009. As a result, the financial information of SandRidge Energy, Inc. is included in the All Other column in the tables below, which is consistent with management s evaluation of the business segments. The operations of SandRidge Energy, Inc. were previously included in the exploration and production segment. All periods presented below reflect this change in presentation.

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Management evaluates the performance of the Company s business segments based on operating income (loss), which is defined as segment operating revenues less operating expenses and depreciation, depletion and amortization. Summarized financial information concerning the Company s segments is shown in the following table (in thousands):

	Exploration and Production	Drilling and Oil Field Services	Midstream Gas Services	All Other	Consolidated Total
Year Ended December 31, 2011					
Revenues	$ 1,237,565	$ 390,485	$ 183,912	$ 10,535	$ 1,822,497
Inter-segment revenue	(265)	(287,187)	(118,731)	(1,101)	(407,284)
Total revenues	$ 1,237,300	$ 103,298	$ 65,181	$ 9,434	$ 1,415,213
Income (loss) from operations(1)	$ 521,117	$ 10,341	$ (12,975)	$ (89,470)	$ 429,013
Interest income (expense), net	509	(95)	(611)	(237,135)	(237,332)
Loss on extinguishment of debt				(38,232)	(38,232)
Other income (expense), net	3,601		(485)	6	3,122
Income (loss) before income taxes	$ 525,227	$ 10,246	$ (14,071)	$ (364,831)	$ 156,571
Capital expenditures(2)	$ 1,714,222	$ 25,674	$ 38,514	$ 54,615	$ 1,833,025
Depreciation, depletion and amortization	$ 328,753	$ 32,582	$ 4,650	$ 14,259	$ 380,244
At December 31, 2011					
Total assets	$ 5,345,527	$ 219,101	$ 138,844	$ 516,137	$ 6,219,609
Year Ended December 31, 2010					
Revenues	$ 779,450	$ 265,262	$ 275,071	$ 35,285	$ 1,355,068
Inter-segment revenue	(259)	(236,687)	(176,549)	(9,837)	(423,332)
Total revenues	$ 779,191	$ 28,575	$ 98,522	$ 25,448	$ 931,736
Income (loss) from operations(1)	$ 88,390	$ (9,970)	$ 3,959	$ (89,165)	$ (6,786)
Interest income (expense), net	496	(920)	(649)	(246,369)	(247,442)
Other income, net	1,251		625	682	2,558
Income (loss) before income taxes	$ 90,137	$ (10,890)	$ 3,935	$ (334,852)	$ (251,670)
Capital expenditures(2)	$ 1,027,933	$ 31,658	$ 48,401	$ 21,661	$ 1,129,653
Depreciation, depletion and amortization	$ 278,110	$ 30,031	$ 4,030	$ 13,940	$ 326,111
At December 31, 2010					
Total assets	$ 4,612,295	$ 224,784	$ 151,598	$ 242,771	$ 5,231,448
Year Ended December 31, 2009					
Revenues	$ 457,397	$ 225,227	$ 299,580	$ 30,654	$ 1,012,858
Inter-segment revenue	(261)	(201,641)	(215,667)	(4,245)	(421,814)
Total revenues	$ 457,136	$ 23,586	$ 83,913	$ 26,409	$ 591,044
Loss from operations(1)	$ (1,487,914)	$ (15,166)	$ (36,989)	$ (64,955)	$ (1,605,024)
Interest income (expense), net	1,121	(2,074)	(1,246)	(183,117)	(185,316)

Other income, net	4,673		3,365	254	8,292
Loss before income taxes	$ (1,482,120)	$ (17,240)	$ (34,870)	$ (247,818)	$ (1,782,048)
Capital expenditures(2)	$ 555,809	$ 4,090	$ 52,425	$ 32,818	$ 645,142
Depreciation, depletion and amortization	$ 178,783	$ 28,221	$ 5,496	$ 14,392	$ 226,892

(1) Exploration and production segment income (loss) from operations includes net (gains) losses of $(44.1) million, $50.9 million and ($147.5) million on commodity derivative contracts for the years ended December 31, 2011, 2010 and 2009, respectively. The loss from operations for the exploration and production segment for the year ended December 31, 2009 includes non-cash full cost ceiling impairments of $1,693.3 million on the Company s oil and natural gas properties. The loss from operations for the midstream gas services segment for the year ended December 31, 2009 includes a $26.1 million loss on the sale of its gathering and compression assets in the Piñon Field.

(2) On an accrual basis and exclusive of acquisitions.

Major Customers. For the years ended 2011, 2010 and 2009, the Company had sales exceeding 10% of total revenues to the following oil and natural gas purchasers (in thousands):

	2011	
	Sales	**% of Revenue**
Enterprise Crude Oil, LLC	$319,277	22.6%
Plains Marketing, L.P.	$276,285	19.5%

	2010	
	Sales	**% of Revenue**
Plains Marketing, L.P.	$ 239,396	25.7%
Conoco Phillips Company	$109,358	11.7%

	2009	
	Sales	**% of Revenue**
Plains Marketing, L.P.	$ 120,097	20.3%

24. Condensed Consolidating Financial Information

The Company provides condensed consolidating financial information for its subsidiaries that are guarantors of its registered debt. The subsidiary guarantors are wholly owned and have jointly and severally guaranteed, on a full, unconditional and unsecured basis, the Company s Senior Floating Rate Notes, 8.75% Senior Notes and 7.5% Senior Notes as of December 31, 2011. Prior to their purchase and redemption, the 8.625% Senior Notes were also jointly and severally guaranteed, on a full, unconditional and unsecured basis by the wholly owned subsidiary guarantors. The subsidiary guarantees (i) rank equally in right of payment with all of the existing and future senior debt of the subsidiary guarantors; (ii) rank senior to all of the existing and future subordinated debt of the subsidiary guarantors; (iii) are effectively subordinated in right of payment to any existing or future secured obligations of the subsidiary guarantors to the extent of the value of the assets securing such obligations; (iv) are structurally subordinated to all debt and other obligations of the subsidiaries of the guarantors who are not themselves guarantors; and (v) are only released under certain customary circumstances. The Company s subsidiary guarantors guarantee payments of principal and interest under the Company s registered notes. The Company has not presented separate financial and narrative information for each of the subsidiary guarantors because it believes that such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the guarantees.

Effective May 1, 2009, SandRidge Energy, Inc., the parent company, contributed all of its rights, title and interest in its oil and natural gas related assets and accompanying liabilities to one of its wholly owned guarantor subsidiaries, leaving it with no oil or natural gas related assets or operations.

The following condensed consolidating financial information represents the financial information of SandRidge Energy, Inc., its wholly owned subsidiary guarantors and its non-guarantor subsidiaries, prepared on the equity basis of accounting. The non-guarantor subsidiaries, including four variable interest entities, are included in the non-guarantors column in the tables below. The financial information may not necessarily be indicative of the financial position, results of operations or cash flows had the subsidiary guarantors operated as independent entities.

Condensed Consolidating Balance Sheets

	Parent	Guarantors	December 31, 2011 Non-Guarantors (In thousands)	Eliminations	Consolidated
ASSETS					
Current assets					
Cash and cash equivalents	$ 204,015	$ 437	$ 3,229	$	$ 207,681
Accounts receivable, net	1,217,096	247,824	602,541	(1,861,125)	206,336
Derivative contracts		2,567	10,368	(8,869)	4,066
Other current assets		16,063	7,694		23,757
Total current assets	1,421,111	266,891	623,832	(1,869,994)	441,840
Property, plant and equipment, net		4,462,846	926,578		5,389,424
Investment in subsidiaries	3,609,244	90,920		(3,700,164)	
Derivative contracts		20,746	35,774	(30,105)	26,415
Goodwill		235,396			235,396
Other assets	51,724	74,760	50		126,534
Total assets	$ 5,082,079	$ 5,151,559	$ 1,586,234	$ (5,600,263)	$ 6,219,609
LIABILITIES AND EQUITY					
Current liabilities					
Accounts payable and accrued expenses	$ 643,376	$ 1,166,029	$ 556,165	$ (1,858,786)	$ 506,784
Derivative contracts	8,475	115,829		(8,869)	115,435
Asset retirement obligation		32,906			32,906
Other current liabilities		43,320	1,051		44,371
Total current liabilities	651,851	1,358,084	557,216	(1,867,655)	699,496
Long-term debt	2,798,147		14,978		2,813,125
Derivative contracts	1,973	77,827		(30,105)	49,695
Asset retirement obligation		95,029	181		95,210
Other long-term obligations	1,758	11,375			13,133
Total liabilities	3,453,729	1,542,315	572,375	(1,897,760)	3,670,659
Equity					
SandRidge Energy, Inc. stockholders equity	1,628,350	3,609,244	1,013,859	(4,625,442)	1,626,011
Noncontrolling interest				922,939	922,939
Total equity	1,628,350	3,609,244	1,013,859	(3,702,503)	2,548,950
Total liabilities and equity	$ 5,082,079	$ 5,151,559	$ 1,586,234	$ (5,600,263)	$ 6,219,609

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	Parent	Guarantors	December 31, 2010 Non-Guarantors (In thousands)	Eliminations	Consolidated
ASSETS					
Current assets					
Cash and cash equivalents	$ 1,441	$ 564	$ 3,858	$	$ 5,863
Accounts receivable, net	1,224,500	141,530	408,015	(1,627,927)	146,118
Derivative contracts		5,028			5,028
Other current assets		13,890	4,691		18,581
Total current assets	1,225,941	161,012	416,564	(1,627,927)	175,590
Property, plant and equipment, net		4,635,747	98,118		4,733,865
Investment in subsidiaries	3,230,067	58,723		(3,288,790)	
Goodwill		234,356			234,356
Other assets	50,637	37,000			87,637
Total assets	$ 4,506,645	$ 5,126,838	$ 514,682	$ (4,916,717)	$ 5,231,448
LIABILITIES AND EQUITY					
Current liabilities					
Accounts payable and accrued expenses	$ 66,539	$ 1,510,827	$ 427,483	$ (1,627,927)	$ 376,922
Derivative contracts	9,007	94,402			103,409
Asset retirement obligation		25,360			25,360
Other current liabilities		37,776	991		38,767
Total current liabilities	75,546	1,668,365	428,474	(1,627,927)	544,458
Long-term debt	2,885,764		16,029		2,901,793
Derivative contracts	7,687	116,486			124,173
Asset retirement obligation		94,350	167		94,517
Other long-term obligations	1,454	17,570			19,024
Total liabilities	2,970,451	1,896,771	444,670	(1,627,927)	3,683,965
Equity					
SandRidge Energy, Inc. stockholders equity	1,536,194	3,230,067	70,012	(3,300,078)	1,536,195
Noncontrolling interest				11,288	11,288
Total equity	1,536,194	3,230,067	70,012	(3,288,790)	1,547,483
Total liabilities and equity	$ 4,506,645	$ 5,126,838	$ 514,682	$ (4,916,717)	$ 5,231,448

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Condensed Consolidating Statements of Operations

	Parent	Guarantors	Non-Guarantors (In thousands)	Eliminations	Consolidated
Year Ended December 31, 2011					
Total revenues	$	$ 1,285,854	$ 268,427	$ (139,068)	$ 1,415,213
Expenses					
Direct operating expenses		475,578	158,697	(135,712)	498,563
General and administrative	416	144,574	4,670	(1,017)	148,643
Depreciation, depletion, amortization and impairment		351,708	31,361		383,069
Gain on derivative contracts		(33,749)	(10,326)		(44,075)
Total expenses	416	938,111	184,402	(136,729)	986,200
(Loss) income from operations	(416)	347,743	84,025	(2,339)	429,013
Equity earnings from subsidiaries	379,177	28,751		(407,928)	
Interest expense, net	(236,109)	(197)	(1,026)		(237,332)
Loss on extinguishment of debt	(38,232)				(38,232)
Other income, net		2,880	242		3,122
Income before income taxes	104,420	379,177	83,241	(410,267)	156,571
Income tax (benefit) expense	(5,984)		167		(5,817)
Net income	110,404	379,177	83,074	(410,267)	162,388
Less: net income attributable to noncontrolling interest				54,323	54,323
Net income attributable to SandRidge Energy, Inc.	$ 110,404	$ 379,177	$ 83,074	$ (464,590)	$ 108,065
Year Ended December 31, 2010					
Total revenues	$	$ 894,621	$ 138,685	$ (101,570)	$ 931,736
Expenses					
Direct operating expenses		366,947	115,912	(100,885)	381,974
General and administrative	882	176,075	3,293	(685)	179,565
Depreciation, depletion, amortization and impairment		319,297	6,814		326,111
Loss on derivative contracts		50,872			50,872
Total expenses	882	913,191	126,019	(101,570)	938,522
(Loss) income from operations	(882)	(18,570)	12,666		(6,786)
Equity earnings from subsidiaries	(10,253)	7,123		3,130	
Interest expense, net	(245,284)	(1,073)	(1,085)		(247,442)
Other income, net	74	2,267	217		2,558
(Loss) income before income taxes	(256,345)	(10,253)	11,798	3,130	(251,670)
Income tax (benefit) expense	(446,910)		230		(446,680)
Net income (loss)	190,565	(10,253)	11,568	3,130	195,010
Less: net income attributable to noncontrolling interest				4,445	4,445

Net income (loss) attributable to SandRidge Energy, Inc.	$ 190,565	$ (10,253)	$ 11,568	$ (1,315)	$ 190,565

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	Parent	Guarantors	Non-Guarantors (In thousands)	Eliminations	Consolidated
Year Ended December 31, 2009					
Total revenues	$ 58,273	$ 498,032	$ 172,585	$ (137,846)	$ 591,044
Expenses					
Direct operating expenses	27,737	262,778	156,032	(137,250)	309,297
General and administrative	15,645	82,691	2,516	(596)	100,256
Depreciation, depletion, amortization and impairment	627,478	1,295,414	11,150		1,934,042
(Gain) loss on derivative contracts	(237,351)	89,824			(147,527)
Total expenses	433,509	1,730,707	169,698	(137,846)	2,196,068
(Loss) income from operations	(375,236)	(1,232,675)	2,887		(1,605,024)
Equity earnings from subsidiaries	(1,227,164)	1,834		1,225,330	
Interest expense, net	(182,009)	(2,167)	(1,140)		(185,316)
Other income, net	103	5,844	2,345		8,292
(Loss) income before income taxes	(1,784,306)	(1,227,164)	4,092	1,225,330	(1,782,048)
Income tax benefit	(8,716)				(8,716)
Net (loss) income	(1,775,590)	(1,227,164)	4,092	1,225,330	(1,773,332)
Less: net income attributable to noncontrolling interest				2,258	2,258
Net (loss) income attributable to SandRidge Energy, Inc.	$ (1,775,590)	$ (1,227,164)	$ 4,092	$ 1,223,072	$ (1,775,590)

Condensed Consolidating Statements of Cash Flows

	Parent	Guarantors	Non-Guarantors (In thousands)	Eliminations	Consolidated
Year Ended December 31, 2011					
Net cash provided by (used in) operating activities	$ 413,954	$ (32,534)	$ 106,483	$ (12,418)	$ 475,485
Net cash provided by (used in) investing activities		32,171	(1,015,141)	64,110	(918,860)
Net cash (used in) provided by financing activities	(211,380)	236	908,029	(51,692)	645,193
Net increase (decrease) in cash and cash equivalents	202,574	(127)	(629)		201,818
Cash and cash equivalents at beginning of year	1,441	564	3,858		5,863
Cash and cash equivalents at end of year	$ 204,015	$ 437	$ 3,229	$	$ 207,681