SANDRIDGE ENERGY INC
Form 424B1
August 12, 2011

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PROSPECTUS

30,000,000 Common Units

SandRidge Permian Trust

Representing Beneficial Interests

This is an initial public offering of common units representing beneficial interests in SandRidge Permian Trust. The trust is selling all of the units offered hereby. SandRidge Energy, Inc. ("SandRidge") will convey to the trust certain royalty interests in exchange for the net proceeds of this offering, as well as common and subordinated units collectively representing a 43% beneficial interest in the trust (without giving effect to the exercise of the underwriters' over-allotment option).

The common units representing beneficial interests have been approved for listing on the New York Stock Exchange under the symbol "PER."

The Trust Units.** **Trust units, consisting of the common and subordinated units, are units representing beneficial interests in the trust and represent undivided beneficial interests in the property of the trust. They do not represent any interest in SandRidge.

The Trust.** **The trust will own term and perpetual royalty interests in certain of SandRidge's properties in the Permian Basin in Andrews County, Texas. These royalty interests will entitle the trust to receive, after the deduction of certain costs, (a) 80% of the proceeds attributable to SandRidge's net revenue interest in the sale of production from 509 producing wells and (b) 70% of the proceeds attributable to SandRidge's net revenue interest in the sale of production from 888 development wells to be drilled on drilling locations included within an area of mutual interest consisting of approximately 16,800 gross acres (15,900 net acres) held by SandRidge. The trust will not be responsible for any costs related to the drilling of the development wells. The trust will be treated as a partnership for U.S. federal income tax purposes.

The Trust Unitholders.** **As a trust unitholder, you will receive quarterly distributions of cash from the proceeds that the trust receives from SandRidge's sale of oil, natural gas and natural gas liquids subject to the royalty interests to be held by the trust. The distributions will also reflect hedges entered into pursuant to a derivatives agreement between the trust and SandRidge, as well as hedges entered into by the trust directly with unaffiliated hedge counterparties. For information on target distributions and related matters pertinent to trust unitholders, please see "Target Distributions and Subordination and Incentive Thresholds."

Investing in the common units involves risks. See "Risk Factors" beginning on page 18.

These risks include the following:

- ***Drilling risks could delay the anticipated drilling schedule for the development wells to be drilled by SandRidge, which could adversely affect future production and decrease distribution to unitholders.***

- ***Oil and natural gas price fluctuations could reduce proceeds to the trust and cash distributions to unitholders.***

- ***Actual reserves and future production may be less than current estimates.***

- ***Estimates of target distributions to unitholders are based on assumptions that are inherently subjective and are subject to significant risks and uncertainties.***

- ***The hedging arrangements will cover only a portion of the expected production attributable to the trust, and such arrangements will limit the trust's ability to benefit from commodity price increases for hedged volumes above the corresponding hedge price.***

- ***If the trust were treated as a corporation for U.S. federal income tax purposes, then its cash available for distribution to unitholders would be substantially reduced.***

- ***If the IRS contests the tax positions the trust takes, the value of the trust units may be adversely affected, the cost of any IRS contest will reduce the trust's cash available for distribution and income, gain, loss and deduction may be reallocated among trust unitholders.***

- ***The tax treatment of an investment in trust units could be affected by potential legislative changes, possibly on a retroactive basis.***

PRICE $18.00 A COMMON UNIT

	Price to Public	***Underwriting Discounts and Commissions(1)***	***Proceeds to Trust(2)***
Per Common Unit	*$18.00*	*$1.08*	*$16.92*
Total	*$540,000,000*	*$32,400,000*	*$507,600,000*

(1) Excludes a structuring fee equal to 0.50% of the gross proceeds of this offering, or approximately $2.7 million, payable to Morgan Stanley & Co. LLC.

(2) The trust will deliver all of the proceeds it receives in this offering to one or more SandRidge subsidiaries. See "Use of Proceeds."

The trust has granted the underwriters the right to purchase up to an additional 4,500,000 common units to cover over-allotments.

The Securities and Exchange Commission and state securities regulators have not approved or disapproved these securities, or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the common units to purchasers on August 16, 2011.

MORGAN STANLEY *RAYMOND JAMES* *RBC CAPITAL MARKETS* *WELLS FARGO SECURITIES*

Deutsche Bank Securities *Goldman, Sachs & Co.* *J.P. Morgan*

Baird *Oppenheimer & Co.* *Morgan Keegan* *Sanders Morris Harris Inc.*

Wunderlich Securities *SunTrust Robinson Humphrey* *Johnson Rice & Company L.L.C.* *Tuohy Brothers*

August 10, 2011

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IMPORTANT NOTICE ABOUT INFORMATION IN THIS PROSPECTUS

You should rely only on the information contained in this prospectus or in any free writing prospectus the trust may authorize to be delivered to you. Until September 4, 2011 (25 days after the date of this prospectus), federal securities laws may require all dealers that effect transactions in the common units, whether or not participating in this offering, to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

The trust and SandRidge have not, and the underwriters have not, authorized anyone to provide you with additional or different information. If anyone provides you with additional, different or inconsistent information, you should not rely on it. This prospectus is not an offer to sell or a solicitation of an offer to buy the common units in any jurisdiction where such offer and sale would be unlawful. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front of this document. The trust's and SandRidge's business, financial condition, results of operations and prospects may have changed since such date.

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SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. To understand this offering fully, you should read the entire prospectus carefully, including the risk factors and the financial statements and notes to those statements. Definitions for terms relating to the oil and natural gas business can be found in "Glossary of Certain Oil and Natural Gas Terms and Terms Related to the Trust." Netherland, Sewell & Associates, Inc., referred to in this prospectus as "Netherland Sewell," an independent engineering firm, provided the estimates of proved oil, natural gas and natural gas liquids reserves as of March 31, 2011 included in this prospectus. These estimates are contained in summaries prepared by Netherland Sewell of their reserve reports for (1) the Underlying Properties held by SandRidge, dated May 23, 2011, and (2) the royalty interests to be held by the trust, dated May 24, 2011. These summaries are included as Annex A to this prospectus and are referred to in this prospectus as the "reserve report."

References to "SandRidge" in this prospectus are to SandRidge Energy, Inc. and, where the context requires, its subsidiaries. The term "Arena Properties" refers to all of the oil and natural gas properties owned by Arena Resources, Inc. ("Arena") at the time of its acquisition by SandRidge in July 2010. The term "Underlying Properties" means the portion of the Arena Properties from which SandRidge will convey the royalty interests to the trust. The royalty interests to be conveyed to the trust are sometimes referred to as the "trust properties."

Unless otherwise indicated, all information in this prospectus assumes no exercise of the underwriters' over-allotment option.

SandRidge Permian Trust

SandRidge Permian Trust is a Delaware statutory trust formed to own royalty interests to be conveyed to the trust by SandRidge in (a) 509 producing wells, including 13 wells currently awaiting completion (the "Producing Wells"), and (b) 888 development wells to be drilled (the "Development Wells") within an "Area of Mutual Interest," or "AMI." The AMI consists of the Grayburg/San Andres formation in the Permian Basin in Andrews County, Texas on the acreage identified on the inside front cover of this prospectus. SandRidge presently holds approximately 16,800 gross acres (15,900 net acres) in the AMI. SandRidge is obligated to drill, or cause to be drilled, the Development Wells from drilling locations in the AMI on or before March 31, 2016. Except in limited circumstances, until SandRidge has satisfied its drilling obligation to the trust, it will not be permitted to drill and complete any wells for its own account within the AMI. See "The Trust Development Agreement and Drilling Support Lien Additional Provisions."

SandRidge acquired the Underlying Properties in July 2010 and expects to operate substantially all of the Underlying Properties. The royalty interest in the Producing Wells (the "PDP Royalty Interest") entitles the trust to receive 80% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of production of oil, natural gas and natural gas liquids attributable to SandRidge's net revenue interest in the Producing Wells. The royalty interest in the Development Wells (the "Development Royalty Interest") entitles the trust to receive 70% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Development Wells.

As of March 31, 2011 and after giving effect to the conveyance of the PDP Royalty Interest and the Development Royalty Interest to the trust, the total reserves estimated to be attributable to the trust were 21.8 million barrels of oil equivalent ("MMBoe"). This amount includes 5.8 MMBoe attributable to the PDP Royalty Interest and 16.0 MMBoe attributable to the Development Royalty Interest. The reserves consist of 96% liquids (87% oil and 9% natural gas liquids) and 4% natural gas.

The percentage of production proceeds to be received by the trust with respect to a well will equal the product of (a) the percentage of proceeds to which the trust is entitled under the terms of the conveyances

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(80% for the Producing Wells and 70% for the Development Wells) multiplied by (b) SandRidge's net revenue interest in the well. SandRidge on average owns a 73.0% net revenue interest in the Producing Wells. Therefore, the trust will have an average 58.4% net revenue interest in the Producing Wells. SandRidge on average owns a 69.3% net revenue interest in the properties in the AMI on which the Development Wells will be drilled, and based on this net revenue interest, the trust would have an average 48.5% net revenue interest in the Development Wells. SandRidge's actual net revenue interest in any particular Development Well may differ from this average.

The trust will not be responsible for any costs related to the drilling of the Development Wells or any other operating and capital costs, except for certain taxes and other post-production costs. The trust's cash receipts in respect of the trust properties will be determined after deducting post-production costs and any applicable taxes associated with the PDP Royalty Interest and the Development Royalty Interest. Post-production costs and applicable taxes will generally consist of production and severance taxes and costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and natural gas liquids produced. Cash distributions to unitholders will reflect hedging arrangements, as well as trust general and administrative expenses.

Hedging arrangements covering a portion of expected production will be implemented in two ways. First, SandRidge will enter into a derivatives agreement with the trust to provide the trust with the effect of specified hedge contracts entered into between SandRidge and third parties. Under the derivatives agreement, SandRidge will pay the trust amounts it receives from its hedge counterparties, and the trust will pay SandRidge any amounts that SandRidge is required to pay such counterparties. Second, the trust will enter into hedge contracts directly with unaffiliated hedge counterparties. As a party to these contracts, the trust will receive payments directly from its counterparties, and be required to pay any amounts owed directly to its counterparties. Under the combined hedging arrangements, approximately 73% of the expected production and 79% of the expected revenues upon which the target distributions are based from August 1, 2011 through March 31, 2015 will be hedged. Under the derivatives agreement, as Development Wells are drilled, SandRidge will have the right to assign or novate to the trust any of the SandRidge-provided hedges in certain circumstances. Please see "The Trust Hedging Arrangements" and "Target Distributions and Subordination and Incentive Thresholds."

The trust will make quarterly cash distributions of substantially all of its cash receipts, after deducting the trust's administrative expenses, on or about 60 days following the completion of each quarter through (and including) the quarter ending March 31, 2031. The first distribution, which will cover the second and third quarters of 2011 (consisting of proceeds attributable to five months of production), is expected to be made on or about November 30, 2011 to record unitholders as of November 15, 2011. The trustee intends to withhold $1.0 million from the first distribution to establish a cash reserve available for trust administrative expenses. The trust will dissolve and begin to liquidate on March 31, 2031 (the "Termination Date") and will soon thereafter wind up its affairs and terminate. At the Termination Date, 50% of the PDP Royalty Interest and 50% of the Development Royalty Interest will revert automatically to SandRidge. The remaining 50% of each of the PDP Royalty Interest and the Development Royalty Interest will be retained by the trust at the Termination Date and thereafter sold, and the net proceeds of the sale, as well as any remaining trust cash reserves, will be distributed to the unitholders in accordance with their interests. SandRidge will have a right of first refusal to purchase the royalty interests retained by the trust at the Termination Date.

SandRidge will retain 20% of the proceeds from the sale of oil, natural gas and natural gas liquids attributable to its net revenue interest in the Producing Wells, as well as 30% of the proceeds from the sale of future production attributable to its net revenue interest in the Development Wells. SandRidge initially will own 43% of the trust units (without giving effect to the exercise of the underwriters' over-allotment option). By virtue of SandRidge's retained interest in the Producing Wells and the Development Wells, as well as its ownership of 43% of the trust units, it will have an effective average net revenue interest of 39.6% in the Producing Wells and 41.6% in the Development Wells, compared with an effective average net revenue interest for the holders of trust units other than SandRidge of 33.4% in the Producing Wells and 27.7% in the Development Wells.

SandRidge operates all of the Producing Wells. SandRidge owns a majority working interest in substantially all of the drilling locations on which it expects to drill the Development Wells, and expects to operate such wells during the subordination period described herein. In addition, for those wells it operates, SandRidge has agreed to operate the properties and cause to be marketed oil, natural gas and natural gas liquids produced from these properties in the same manner it would if such properties were not burdened by the royalty interests.

The business and affairs of the trust will be managed by The Bank of New York Mellon Trust Company, N.A., as trustee. The trustee will have no ability to manage or influence the operation of the Underlying Properties. SandRidge expects to operate substantially all of the Underlying Properties, but will have no ability to manage or influence the management of the trust except through its limited voting rights as a holder of trust units and its limited ability to manage the hedging program. Please see "The Trust Hedging Arrangements," "The Trust Administrative Services Agreement" and "Description of the Trust Units Voting Rights of Trust Unitholders."

The Development Wells

Pursuant to a development agreement with the trust, SandRidge is obligated to drill, or cause to be drilled, 888 Development Wells in the AMI on or before March 31, 2015. In the event of delays, SandRidge will have until March 31, 2016 to fulfill its drilling obligation. SandRidge will be credited for drilling one full Development Well if the well is drilled and completed in the Grayburg/San Andres formation and SandRidge's net revenue interest in the well is equal to 69.3%. For wells in which SandRidge has a net revenue interest greater than or less than 69.3%, SandRidge will receive credit for such well in the proportion that its net revenue interest in the well bears to 69.3%. As a result, SandRidge may be required to drill more or less than 888 wells in order to fulfill its drilling obligation. In addition, in certain circumstances, SandRidge may receive additional Development Well credit for drilling horizontal wells. See "The Trust Development Agreement and Drilling Support Lien."

SandRidge is required to adhere to a reasonably prudent operator standard, which requires that it act with respect to the Underlying Properties as it would act with respect to its own properties, disregarding the existence of the royalty interests as burdens affecting such properties. Accordingly, SandRidge expects that the drilling and completion techniques used for the Development Wells will be generally consistent with those used for the Producing Wells within the AMI and other producing wells outside of the AMI that have targeted the Grayburg/San Andres formation. The proved undeveloped reserves reflected in the reserve report assume that SandRidge will drill and complete the 888 Development Wells with the same completion technique, and bearing the same capital and other costs, as the 509 Producing Wells.

SandRidge Exploration and Production, LLC ("SandRidge E&P"), a wholly owned subsidiary of SandRidge, will grant to the trust a lien on its interest in the AMI (except the Producing Wells and any other wells which are already producing and not subject to the royalty interests) in order to secure the estimated amount of the drilling costs for the trust's interests in the Development Wells (the "Drilling Support Lien"). The amount obtained by the trust pursuant to the Drilling Support Lien may not exceed approximately $295 million. As SandRidge fulfills its drilling obligation over time, the total dollar amount that may be recovered will be proportionately reduced and the drilled Development Wells will be released from the lien. After SandRidge has satisfied its drilling obligation under the development agreement, it may sell, without the consent or approval of the trust unitholders, all or any part of its interest in the Underlying Properties, as long as such sale is subject to and burdened by the royalty interests.

As of the date of this prospectus, SandRidge's drilling activity with respect to the Development Wells is consistent with the drilling schedule contemplated by the development agreement.

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Underlying Properties

The Underlying Properties are located in the greater Fuhrman-Mascho field area, a region in Andrews County, Texas that primarily produces oil from the Grayburg/San Andres formation within the Permian Basin. SandRidge currently operates three drilling rigs within the AMI and, as of March 31, 2011, had drilled 101 wells since acquiring the properties in July 2010. Within the AMI, SandRidge operates 509 wells and has 888 proven undeveloped locations as of March 31, 2011. These 888 proven locations are a combination of 5-acre, 10-acre and 20-acre infill spacing locations. As of March 31, 2011, average daily production from the Underlying Properties was approximately 3,400 Boe/d.

Permian Basin. The Permian Basin extends throughout southwest Texas and southeast 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 U.S. crude oil production, making this basin the second largest oil producing area 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.

SandRidge currently operates approximately 2,600 gross producing wells in the Permian Basin, with an average working interest of 94%. SandRidge's average daily net production for the month of March 2011 in the Permian Basin was approximately 28,800 Boe/d. SandRidge was operating 16 rigs in the basin as of March 2011. SandRidge drilled 484 wells in this area in 2010 and expects to drill over 800 wells in 2011.

Fuhrman-Mascho Field. The Fuhrman-Mascho field is located near the center of the Central Basin Platform in the Permian Basin. The field 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 since its discovery in 1930, the field has produced approximately 142 MMBoe. SandRidge currently operates eight drilling rigs in the area and has drilled 307 wells as of March 31, 2011 since acquiring the properties in July 2010.

Target Distributions and Subordination and Incentive Thresholds

SandRidge has calculated quarterly target levels of cash distributions to unitholders for the life of the trust as set forth on Annex B to this prospectus. The amount of actual quarterly distributions may fluctuate from quarter to quarter, depending on the proceeds received by the trust, payments under the hedge arrangements, the trust's administrative expenses and other factors. Annex B reflects that while target distributions initially increase as SandRidge completes its drilling obligation and production increases, over time target distributions decline as a result of the depletion of the reserves in the Underlying Properties. While these target distributions do not represent the actual distributions you will receive with respect to your common units, they were used to calculate the subordination and incentive thresholds described in more detail below. The target distributions were derived by assuming that oil, natural gas and natural gas liquids production from the trust properties will equal the volumes reflected in the reserve report attached as Annex A to this prospectus, adjusted for actual volumes realized in April, May and June 2011, and that prices received for such production will be consistent with settled NYMEX pricing for April through June 2011, monthly NYMEX forward pricing as of July 15, 2011 for the remainder of the period ending March 31, 2014, and assumed price increases after March 31, 2014 of 2.5% annually, capped at $120.00 per Bbl of oil and $7.00 per MMBtu of natural gas. Using these assumptions, the price of oil would reach the $120.00 per Bbl cap in 2023, and the price of natural gas would reach the $7.00 per MMBtu cap in 2022. The target distributions also give effect to estimated post-production expenses and assumed trust general and administrative expenses.

In order to provide support for cash distributions on the common units, SandRidge has agreed to subordinate 13,125,000 of the trust units it will retain following this offering, which will constitute 25% of the total trust units outstanding. The subordinated units will be entitled to receive pro rata distributions from the 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 of the common units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on all the common units, including the common units held by SandRidge. Each quarterly subordination threshold is 20% below the target distribution level for the corresponding quarter (each, a "subordination threshold").

In exchange for agreeing to subordinate a majority of its trust units, and in order to provide additional financial incentive to SandRidge to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, SandRidge will be entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the trust units in any quarter is 20% greater than the target distribution for such quarter (each, an "incentive threshold"). The remaining 50% of cash available for distribution in excess of the incentive thresholds will be paid to trust unitholders, including SandRidge, on a pro rata basis.

By way of example, if the target distribution per unit for a particular quarterly period is $.55, then the subordination threshold would be $.44 and the incentive threshold would be $.66 for such quarter. This means that if the cash available for distribution to all holders for that quarter would result in a per unit distribution below $.44, the distribution to be made with respect to subordinated units will be reduced or eliminated in order to make a distribution, to the extent possible, up to the amount of the subordination threshold, on the common units. If, on the other hand, the cash available for distribution to all holders would result in a per unit distribution above $.66, then SandRidge would receive 50% of the amount by which the cash available for distribution on all the trust units exceeds $.66, with all trust unitholders (including SandRidge on a pro rata basis) sharing in the other 50% of such excess amount. See "Target Distributions and Subordination and Incentive Thresholds."

At the end of the fourth full calendar quarter following SandRidge's satisfaction of its drilling obligation with respect to the Development Wells, the subordinated units will automatically convert into common units on a one-for-one basis and SandRidge's right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all trust unitholders will share on a pro rata basis in the trust's distributions. SandRidge currently expects that it will complete its drilling obligation on or before March 31, 2015 and that, accordingly, the subordinated units will convert into common units on or before March 31, 2016. In the event of delays, SandRidge will have until March 31, 2016 under its contractual obligation to drill all the Development Wells, in which event the subordinated units would convert into common units on or before March 31, 2017. The period during which the subordinated units are outstanding is referred to as the "subordination period."

SandRidge's management has prepared the prospective financial information set forth below to present the target distributions to the holders of the trust units based on the estimates and assumptions described under "Target Distributions and Subordination and Incentive Thresholds." The accompanying prospective financial information was not prepared with a view toward complying with the guidelines of the U.S. Securities and Exchange Commission ("SEC") or the guidelines established by the American Institute of Certified Public Accountants with respect to preparation and presentation of prospective financial information. More specifically, such information omits items that are not relevant to the trust. SandRidge's management believes the prospective financial information was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management's knowledge and belief, the expected course of action and the expected future financial performance of the royalty interests. However, this information is based on estimates and judgments, and readers of this prospectus are cautioned not to place undue reliance on the prospective financial information.

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The prospective financial information included in this prospectus has been prepared by, and is the responsibility of, SandRidge's management. Neither PricewaterhouseCoopers LLP, the trust's and SandRidge's independent registered public accountant, nor Hansen Barnett & Maxwell, P.C., Arena Resources, Inc.'s independent registered public accountant, has examined, compiled or performed any procedures with respect to the accompanying prospective financial information and, accordingly, neither PricewaterhouseCoopers LLP nor Hansen Barnett & Maxwell, P.C. expresses an opinion or any other form of assurance with respect thereto. The reports of PricewaterhouseCoopers LLP included in this prospectus relate to the Statement of Assets and Trust Corpus of the trust and the historical Statements of Revenues and Direct Operating Expenses of the Arena Properties, and the report of Hansen Barnett & Maxwell, P.C. included in this prospectus relates to the historical consolidated financial statements of Arena Resources, Inc. The foregoing reports do not extend to the prospective financial information and should not be read to do so.

The following table sets forth the target distributions and subordination and incentive thresholds for each calendar quarter through the first quarter of 2017. The effective date of the conveyance of the royalty interests is April 1, 2011, which means that the trust will be credited with the proceeds of production attributable to the royalty interests from that date even though the trust properties will not be conveyed to the trust until the closing of this offering. Please see " Calculation of Target Distributions" below. The first distribution, which will cover the second and third quarters of 2011, is expected to be made on or about November 30, 2011 to record unitholders as of November 15, 2011. Due to the timing of the payment of production proceeds to the trust, the trust expects that the first distribution will include sales for oil, natural gas and natural gas liquids for five months. Thereafter, quarterly distributions will generally include royalties attributable to sales of oil, natural gas and natural gas liquids for three months, including

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one month of the prior quarter. The trustee intends to withhold $1.0 million from the first distribution to establish a cash reserve available for trust administrative expenses.

Period	Subordination Threshold[(1)]	Target Distribution	Incentive Threshold[(1)]
		(per unit)	
2011:			
Second and Third Quarters[(2)]	$ .53	$ .66	$ .79
Fourth Quarter	.39	.49	.59
2012:			
First Quarter	.42	.53	.63
Second Quarter	.44	.55	.66
Third Quarter	.47	.58	.70
Fourth Quarter	.49	.62	.74
2013:			
First Quarter	.51	.64	.77
Second Quarter	.53	.66	.80
Third Quarter	.56	.70	.84
Fourth Quarter	.58	.73	.87
2014:			
First Quarter	.61	.76	.91
Second Quarter	.63	.79	.95
Third Quarter	.65	.82	.98
Fourth Quarter	.66	.82	.98
2015:			
First Quarter	.64	.80	.96
Second Quarter	.61	.77	.92
Third Quarter	.56	.70	.85
Fourth Quarter	.54	.68	.81
2016:			
First Quarter	.53	.67	.80
Second Quarter	.52	.65	.78
Third Quarter	.51	.64	.77
Fourth Quarter	.50	.63	.75
2017:			
First Quarter	.49	.61	.74

(1) The subordination and incentive thresholds terminate after the fourth full calendar quarter following SandRidge's completion of its drilling obligation.

(2) Includes proceeds attributable to the first five months of production from April 1, 2011 to August 31, 2011, and gives effect to $1.0 million of reserves for general and administrative expenses withheld by the trustee and additional administrative costs relating to the formation of the trust.

For additional information with respect to the subordination and incentive thresholds, please see "Target Distributions and Subordination and Incentive Thresholds" and "Description of the Royalty Interests."

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Calculation of Target Distributions

The following table presents the calculation of the target distributions for each quarter through and including the quarter ending June 30, 2012. The target distributions were prepared by SandRidge based on assumptions of production volumes, pricing and other factors. The production forecasts used to calculate target distributions are based on estimates by Netherland Sewell. Payments to unitholders will generally be made 60 days following each calendar quarter. SandRidge will make payments to the trust that will include cash from production from the first two months of the quarter just ended as well as the last month of the immediately preceding quarter. Actual cash distributions to the trust unitholders will fluctuate quarterly based on the quantity of oil, natural gas and natural gas liquids produced from the Underlying Properties, the prices received for oil, natural gas and natural gas liquids production, when SandRidge receives payment for such production and other factors. Please read "Target Distributions and Subordination and Incentive Thresholds Significant Assumptions Used to Calculate the Target Distributions."

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On a pro forma basis, the trust's distributable income was $60.7 million ($1.16 per unit) for the year ended December 31, 2010, and $19.7 million ($0.37 per unit) for the three months ended March 31, 2011. See "Unaudited Pro Forma Financial Information."

	September 30, 2011[1]	December 31, 2011	March 31, 2012	June 30, 2012
	(In thousands, except volumetric and per unit data)			
Estimated production from trust properties				
Oil sales volumes (MBbl)	384	278	294	306
Natural gas sales volumes (MMcf)	107	74	78	80
Natural gas liquids volumes (MBbl)	40	29	30	32
Total sales volumes (MBoe)	441	319	337	351
% Proved developed producing (PDP) sales volumes	88%	57%	48%	42%
% Proved undeveloped (PUD) sales volumes	12%	43%	52%	58%
% Oil volumes	87%	87%	87%	87%
% Natural gas volumes	4%	4%	4%	4%
% Natural gas liquids volumes	9%	9%	9%	9%
Commodity price and derivative contract positions				
NYMEX futures price[2]				
Oil ($/Bbl)	$ 99.33	$ 98.03	$ 99.48	$ 100.70
Natural gas ($/MMBtu)	$ 4.40	$ 4.57	$ 4.88	$ 4.81
Natural gas liquids ($/Bbl)	$ 49.61	$ 49.01	$ 49.74	$ 50.35
Assumed realized weighted unhedged price[3]				
Oil ($/Bbl)	$ 95.97	$ 93.76	$ 95.21	$ 96.43
Natural gas ($/Mcf)	3.17	3.29	3.51	3.46
Natural gas liquids ($/Bbl)	47.97	47.40	48.10	48.69
Assumed realized weighted hedged price				
Oil ($/Bbl)	96.53	95.34	97.04	97.85
Natural gas ($/Mcf)	3.17	3.29	3.51	3.46
Percent of oil volumes hedged	98%[4]	89%	93%	95%
Oil hedged price ($/Bbl)	99.80	99.80	101.46	102.20
Percent of natural gas volumes hedged	0%	0%	0%	0%
Natural gas hedged price ($/MMBtu)				
Estimated cash available for distribution				
Oil sales revenues	$ 36,814	$ 26,067	$ 27,982	$ 29,552
Natural gas sales revenues	338	243	273	279
Natural gas liquids sales revenue	1,916	1,374	1,463	1,536
Realized gains (losses) from derivative contracts	215	441	539	436
Operating revenues and realized gains (losses) from derivative contracts	$ 39,283	$ 28,125	$ 30,257	$ 31,803
Production taxes	(1,862)	(1,320)	(1,417)	(1,496)
Ad valorem taxes	(977)	(692)	(743)	(784)
Franchise taxes	(137)	(98)	(106)	(111)
Trust administrative expenses	(1,750)[5]	(325)	(325)	(325)
Total trust expenses	(4,727)	(2,436)	(2,591)	(2,716)
Cash available for distribution	$ 34,556	$ 25,689	$ 27,666	$ 29,087
Trust units outstanding	52,500	52,500	52,500	52,500
Target distribution per trust unit	$ .66	$ .49	$ .53	$ .55
Subordination threshold per trust unit	$ ..53	$ ..39	$ ..42	$ ..44
Incentive threshold per trust unit	$ ..79	$ ..59	$ ..63	$ ..66

(1) Includes proceeds attributable to the first five months of production from April 1, 2011 to August 31, 2011.

(2) Average NYMEX futures prices, as reported July 15, 2011. For a description of the effect of lower NYMEX prices on target distributions, please read "Target Distributions and Subordination and Incentive Thresholds Sensitivity of Target Distributions to Changes in Oil, Natural Gas and Natural Gas Liquids Prices and Volumes."

(3) Sales price net of forecasted quality, Btu content, transportation costs, and marketing costs. For information about the estimates and assumptions made in preparing the table above, see "Target Distributions and Subordination and Incentive Thresholds Significant Assumptions Used to Calculate the Target Distributions."

(4) Hedging percentage excludes production from April 1, 2011 to July 31, 2011.

(5) Includes trustee cash reserve of $1.0 million and additional administrative costs relating to the formation of the trust.

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SandRidge Energy, Inc.

SandRidge is a publicly traded, independent oil and natural gas company concentrating on development and production activities related to the exploitation of its significant holdings in West Texas and the Mid-Continent area of Oklahoma and Kansas. As of July 28, 2011, its market capitalization was approximately $4.8 billion, and as of December 31, 2010 it had total estimated net proved reserves of 545.9 MMBoe. SandRidge has approximately 210,000 net acres in the Permian Basin. SandRidge also owns and operates other interests in the Mississippian Formation, Mid-Continent, Cotton Valley Trend in East Texas, Gulf Coast and Gulf of Mexico. SandRidge also owns and operates gas gathering and processing facilities, CO_2 treating and transportation facilities, and drilling rig, oil field service and oil and gas marketing businesses.

SandRidge's principal executive offices are located at 123 Robert S. Kerr Avenue, Oklahoma City, Oklahoma 73102 and its telephone number is (405) 429-5500. Its website is *http://www.sandridgeenergy.com*. The principal offices of the trust are located at 919 Congress Avenue, Suite 500, Austin, Texas 78701, and its telephone number is (512) 236-6599.

The trust units do not represent interests in or obligations of SandRidge.

Key Investment Considerations

The following are some key investment considerations related to the Underlying Properties, the royalty interests and the common units:

Well established production history in the region. The Underlying Properties are located in the greater Fuhrman-Mascho field area in the Permian Basin. The Fuhrman-Mascho field is the 34th largest U.S. oil field based on U.S. Energy Information Association estimates of 2009 proved reserves. The field was discovered in 1930 and produced approximately 4.1 MMBbls in 2009, up 24% from 2007 production of 3.3 MMBbls. Since acquiring Arena in July 2010, SandRidge has drilled 101 wells and currently operates 496 producing wells in the AMI.

Royalty interests not burdened by operating or capital costs. The trust will not be responsible for any operating or capital costs associated with the Underlying Properties, including the costs to drill the Development Wells. The trust will bear post-production costs, certain taxes and trust administrative expenses.

Exposure to oil price volatility mitigated through March 31, 2015. Hedging arrangements covering a portion of expected production will be implemented both pursuant to a derivatives agreement between the trust and SandRidge and hedges entered into by the trust directly with unaffiliated hedge counterparties. Under the combined hedging arrangements, approximately 73% of the expected production and approximately 79% of the expected revenues upon which the target distributions are based from August 1, 2011 through March 31, 2015 will be hedged. These hedging arrangements should reduce commodity price risk inherent in holding interests in oil through March 31, 2015.

Potential for initial depletion to be offset by results of development drilling. SandRidge is obligated to drill the Development Wells by March 31, 2015 or, in the event of delays, March 31, 2016. Based on the anticipated drilling schedule, the average daily production net to the trust is expected to increase from 2,700 Boe/d for March 2011 to 5,700 Boe/d for July 2014, after which time production will decline until the termination of the trust.

Alignment of interests between SandRidge and the trust unitholders. SandRidge has significant incentives to complete its drilling obligation and increase production from the Underlying Properties as a result of the following factors:

By virtue of SandRidge's 20% retained interest in the Producing Wells and its 30% retained interest in the Development Wells, as well as its ownership of 43% of the trust units, it will have an effective average net revenue interest of 39.6% in the Producing Wells and 41.6% in the Development Wells, compared with an effective average net revenue interest for the holders of trust units other than SandRidge of 33.4% in the Producing Wells and 27.7% in the Development Wells.

A majority of the trust units that SandRidge will own, constituting 25% of the total trust units outstanding, will be subordinated units that will not be entitled to receive distributions unless there is sufficient cash to pay the amount of the subordination threshold to the common units. These subordinated units will only convert into common units at the end of the fourth full calendar quarter following SandRidge's satisfaction of its drilling obligation to the trust.

To the extent that the trust has cash available for distribution in excess of the incentive thresholds during the subordination period, SandRidge will be entitled to receive 50% of such cash as incentive distributions, plus its pro rata share of the remaining 50% of such cash by virtue of its ownership of 22,500,000 trust units.

Except in limited circumstances, SandRidge will not be permitted to drill and complete any wells for its own account within the AMI or sell the Underlying Properties until it has satisfied its drilling obligation.

SandRidge's experience as an operator in the Permian Basin. Since 2009, SandRidge has drilled, as operator, 315 wells targeting the Grayburg/San Andres formation in the Permian Basin. The majority of the wells drilled in the Grayburg/San Andres formation have been drilled in Andrews County, the location of the Underlying Properties. SandRidge operates all of the Producing Wells. SandRidge owns a majority working interest in substantially all of the locations on which it expects to drill the Development Wells, and it expects to operate such wells during the subordination period, allowing SandRidge to control the timing and amount of discretionary expenditures for operational and development activities with respect to substantially all of the Development Wells.

Rigs and services readily available to allow timely drilling and completion of wells. As of March 31, 2011, SandRidge had eight rigs operating in the greater Fuhrman-Mascho field area and plans to drill more than 450 wells targeting the Grayburg/San Andres formations in 2011, some of which are in the AMI. SandRidge estimates that only three rigs will be required to complete its drilling obligation within its contractual commitment to the trust. SandRidge owns and operates drilling rigs and a related oil field services business that provides pulling units, trucking, rental tools, location and road construction and roustabout services. As of March 31, 2011, SandRidge owned 31 drilling rigs, which it uses to drill wells for its own account as well as that of other oil and natural gas companies. SandRidge will use a combination of its own rigs and oil field services business and third party rigs and services to drill and complete the Development Wells. SandRidge's direct access to drilling rigs and related oil field services should substantially mitigate any potential shortage of drilling and completion equipment and enable SandRidge to achieve its projected drilling schedule.

Recognized sponsor with a successful track record and experienced management. SandRidge has a history of active and successful drilling. From the beginning of 2007 through December 31, 2010, SandRidge drilled 1,542 gross (1,404 net) oil and gas wells, investing $4.5 billion in exploration and production activity. During this same period, SandRidge produced over 65 MMBoe of oil and gas. SandRidge currently operates approximately 5,000 wells. SandRidge's executive management team averages over 25 years of experience in the oil and gas industry, and SandRidge's field personnel have extensive operational experience.

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Proved Reserves

Proved Reserves of Underlying Properties and Royalty Interests. The following table sets forth certain estimated proved reserves and the PV-10 value as of March 31, 2011 attributable to the Underlying Properties, the PDP Royalty Interest and the Development Royalty Interest, in each case derived from the reserve report. The reserve report was prepared by Netherland Sewell in accordance with criteria established by the SEC.

Proved reserve quantities attributable to the royalty interests are calculated by multiplying the gross reserves for each property attributable to SandRidge's interest by the royalty interest assigned to the trust in each property. The reserves related to the Underlying Properties include all proved reserves expected to be economically produced during the life of the properties. The reserves and revenues attributable to the trust's interests include only the reserves attributable to the Underlying Properties that are expected to be produced within the 20-year period in which the trust owns the term royalty interest as well as the residual interest in the reserves that the trust will own on the Termination Date. A summary of the reserve report is included as Annex A to this prospectus.

	Proved Reserves[1]			
	Oil (MBbl)[2]	Natural Gas (MMcf)	Total (MBoe)	PV-10 Value[3] (Dollars in millions)
Underlying Properties	30,644	7,215	31,847	$ 580.8
Royalty Interests:				
PDP Royalty Interests (80%)[4]	5,577	1,375	5,806	$ 213.7
Development Royalty Interests (70%)	15,401	3,570	15,996	$ 555.8
Total	20,977	4,945	21,802	$ 769.5

(1) The proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas for the period from April 1, 2010 through March 1, 2011, without giving effect to derivative transactions, and were held constant for the life of the properties. The prices used in the reserve report, as well as SandRidge's internal reports, yield weighted average prices at the wellhead, which are based on first-day-of-the-month reference prices and adjusted for transportation and regional price differentials. The reference prices and the equivalent weighted average wellhead prices are both presented in the table below.

	Reference prices		Weighted average wellhead prices	
	Oil (per Bbl)	Natural gas (per Mcf)	Oil (per Bbl)	Natural gas (per Mcf)
March 31, 2011	$ 80.04	$ 4.102	$ 75.58	$ 3.003

(2) Includes natural gas liquids.

(3) PV-10 is the present value of estimated future net revenue to be generated from the production of proved reserves, discounted using an annual discount rate of 10%, calculated without deducting future income taxes. PV-10 is a non-GAAP financial measure and generally differs from standardized measure of discounted net cash flows, or Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Because the historical financial information related to the Underlying Properties consists solely of revenues and direct operating expenses and does not include the effect of income taxes, we expect the PV-10 and Standardized Measure attributable to the Underlying Properties for each period to be equivalent. Because the trust will not bear federal income tax expense, we also expect the PV-10 and Standardized Measure attributable to the royalty interests for each period to be

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equivalent. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Underlying Properties or the royalty interests. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(4) Includes reserves associated with wells in the process of being completed.

Annual Production Attributable to Royalty Interests. The following bar graph shows estimated annual production from the Producing Wells and the Development Wells based on the pricing and other assumptions set forth in the reserve report. The production estimates include the impact of additional production that is expected as a result of the drilling of the Development Wells.

Key Risk Factors

Below is a summary of certain key risk factors related to the Underlying Properties, the royalty interests and the common units. This list is not exhaustive. Please also read carefully the full discussion of these risks and other risks described under "Risk Factors" beginning on page 18.

Drilling for and producing oil, natural gas and natural gas liquids on the Underlying Properties are high risk activities with many uncertainties that could delay the anticipated drilling schedule for the Development Wells and adversely affect future production from the Underlying Properties. Any such delays or reductions in production could decrease future revenues that are available for distribution to unitholders.

Oil, natural gas and natural gas liquids prices fluctuate due to a number of factors that are beyond the control of the trust and SandRidge, and lower prices could reduce proceeds to the trust and cash distributions to unitholders.

Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the trust and the value of the trust units.

In certain circumstances the trust may have to make cash payments under the hedging arrangements and these payments could be significant.

Estimates of target distributions to unitholders, subordination thresholds and incentive thresholds are based on assumptions that are inherently subjective and are subject to significant business,

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economic, financial, legal, regulatory and competitive risks and uncertainties that could cause actual cash distributions to differ materially from those estimated.

The subordination of certain trust units held by SandRidge does not assure that you will in fact receive any specified return on your investment in the trust.

The hedging arrangements will cover only a portion of the expected production attributable to the trust, and such contracts limit the trust's ability to benefit from commodity price increases for hedged volumes above the corresponding hedge price. In addition, the trust may be required to pay its counterparties under the hedging arrangements. Following this offering, the trust will not have the ability to enter into additional hedges on its own, except in the limited circumstances involving the restructuring of an existing hedge.

Conflicts of interest could arise between SandRidge and the trust unitholders.

The trust's tax treatment depends on its status as a partnership for U.S. federal income tax purposes. If the U.S. Internal Revenue Service ("IRS") were to treat the trust as a corporation for U.S. federal income tax purposes, then its cash available for distribution to unitholders would be substantially reduced.

The tax treatment of an investment in trust units could be affected by recent and potential legislative changes, possibly on a retroactive basis.

The trust will adopt positions that may not conform to all aspects of existing Treasury Regulations. If the IRS contests the tax positions the trust takes, the value of the trust units may be adversely affected, the cost of any IRS contest will reduce the trust's cash available for distribution and income, gain, loss and deduction may be reallocated among trust unitholders.

Structure of the Trust

The following chart shows the relationship of SandRidge, the trust and the public unitholders (without giving effect to the exercise of the underwriters' over-allotment option).

*

SandRidge will have an effective average net revenue interest of 39.6% in the Producing Wells and 41.6% in the Development Wells. Public unitholders (that is, holders of trust units other than SandRidge) will have an effective average net revenue interest of 33.4% in the Producing Wells and 27.7% in the Development Wells.

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THE OFFERING

Common units offered to public	30,000,000 common units (34,500,000 common units, if the underwriters exercise their over-allotment option in full)
Trust units owned by SandRidge after the offering	9,375,000 common units and 13,125,000 subordinated units (4,875,000 common units and 13,125,000 subordinated units, if the underwriters exercise their over-allotment option in full) See "The Trust Formation Transactions."
Total units outstanding after the offering	52,500,000 trust units, consisting of 39,375,000 common units and 13,125,000 subordinated units
Over-allotment option	4,500,000 common units will be issued and retained by the trust at the initial closing, to be used to satisfy (if necessary) the over-allotment option granted to the underwriters. If the over-allotment option is exercised, the trust will sell to the underwriters such number of the retained units as is necessary to satisfy the over-allotment option, and will then deliver the net proceeds of such sale, together with any remaining unsold units, to SandRidge (or a SandRidge subsidiary) as partial consideration for the conveyance of the perpetual royalty interests. If the over-allotment option is not exercised by the underwriters, the retained units will be delivered to SandRidge (or a SandRidge subsidiary), as partial consideration for the conveyance of the perpetual royalty interests, promptly following the 30th day after the initial closing.
Directed unit program	The underwriters have reserved up to 5% of the common units being offered by this prospectus for sale to SandRidge's directors, officers, and certain other persons associated with SandRidge, at the initial public offering price. The sales will be made by Morgan Stanley & Co. LLC through a directed unit program. See "Underwriters Directed Unit Program."
Use of proceeds	The trust is offering the common units to be sold in this offering. Assuming no exercise of the underwriters' over-allotment option, the estimated net proceeds of this offering will be approximately $502.6 million, after deducting underwriting discounts and commissions and offering expenses. The trust will deliver the net proceeds to one or more wholly-owned subsidiaries of SandRidge as full consideration for the conveyance of the term royalty interests and, if applicable, as partial consideration for the conveyance of the perpetual royalty interests. SandRidge intends to use the offering proceeds, including proceeds from any exercise of the underwriters' over-allotment option, to repay borrowings under its credit facility and for general corporate purposes, which may include the funding of the drilling obligation.

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	Affiliates of Morgan Stanley & Co. LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co., J.P. Morgan Securities LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc. and Wells Fargo Securities, LLC are lenders under the SandRidge credit facility being repaid with the offering proceeds being paid to SandRidge and will therefore receive a portion of the proceeds of the offering. See "Use of Proceeds" and "Underwriters."
NYSE symbol	"PER"
Trustee	The Bank of New York Mellon Trust Company, N.A.
Quarterly cash distributions	Quarterly cash distributions during the term of the trust will be made by the trustee on or about the 60th day following the end of each calendar quarter to unitholders of record on or about the 45th day following each calendar quarter. The first distribution, which will cover the second and third quarters of 2011, is expected to be made on or about November 30, 2011 to record unitholders as of November 15, 2011. Due to the timing of the payment of production proceeds to the trust, the trust expects that the first distribution will include sales for oil, natural gas and natural gas liquids for five months. The trustee intends to withhold $1.0 million from the first distribution to establish a cash reserve available for trust administrative expenses. Actual cash distributions to the trust unitholders will fluctuate quarterly based on the quantity of oil, natural gas and natural gas liquids produced from the Underlying Properties, the prices received for oil, natural gas and natural gas liquids production and other factors. Because payments to the trust will be generated by depleting assets and production from the Underlying Properties will diminish over time, a portion of each distribution will represent a return of your original investment. Given that the production from the Underlying Properties is expected to initially increase and then subsequently decline over time, the target distributions are also expected to initially increase before declining over time.
Voting rights in the trust	Matters voted on by trust unitholders will generally be subject to approval by holders of a majority of the common units (excluding common units owned by SandRidge and its affiliates) and holders of a majority of the trust units, in each case voting in person or by proxy at a meeting of such holders at which a quorum is present. SandRidge will not be entitled to vote on the removal of the trustee or appointment of a successor trustee. However, at any time SandRidge and its affiliates own less than 10% of the total trust units outstanding, matters voted on by trust unitholders will be subject to approval by a majority of the trust units, including units owned by SandRidge, voting in person or by proxy at a meeting of such holders at which a quorum is present.

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Termination of the trust	The trust will dissolve and begin to liquidate on the Termination Date, which is March 31, 2031, and will soon thereafter wind up its affairs and terminate. At the Termination Date, 50% of the PDP Royalty Interest and 50% of the Development Royalty Interest will revert automatically to SandRidge. The remaining 50% of each of the PDP Royalty Interest and the Development Royalty Interest will be retained by the trust at the Termination Date and thereafter sold, and the net proceeds of the sale, as well as any remaining trust cash reserves, will be distributed to the unitholders in accordance with their interests. SandRidge will have a right of first refusal to purchase the royalty interests retained by the trust at the Termination Date.
U.S. federal income tax considerations	The trust will be treated as a partnership for U.S. federal income tax purposes. Consequently, the trust will not incur any U.S. federal income tax liability. Instead, trust unitholders will be allocated an amount of the trust's income, gain, loss or deductions corresponding to their interest in the trust, which amounts may differ in timing or amount from actual distributions. The Term PDP Royalty will, and the Term Development Royalty should, be treated as debt instruments for U.S. federal income tax purposes. The trust will be required to treat a portion of each payment it receives with respect to each such royalty interests as interest income in accordance with the "noncontingent bond method" under the original issue discount rules contained in the Internal Revenue Code of 1986, as amended, and the corresponding IRS regulations. The Perpetual PDP Royalty and the Perpetual Development Royalty will be granted on a perpetual basis. The Perpetual PDP Royalty will and the Perpetual Development Royalty should be treated as mineral royalty interests for U.S. federal income tax purposes, generating ordinary income subject to depletion. Please read "U.S. Federal Income Tax Considerations" for more information.
Estimated ratio of taxable income to distributions	SandRidge estimates that if you own the units you purchase in this offering through the record date for distributions for the period ending December 31, 2013, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be approximately 60% of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $1.00 per unit, the trust estimates that your average allocable federal taxable income per year will be approximately $.60 per unit. Please read "U.S. Federal Income Tax Considerations" for more information.

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RISK FACTORS

You should carefully consider the risks described below before making an investment decision. The trust's cash available for distribution could be materially adversely affected by any of these risks. The trading price of the common units could decline due to any of these risks, or you may lose all or part of your investment.

Risks Related to the Units

Drilling for and producing oil, natural gas and natural gas liquids on the Underlying Properties are high risk activities with many uncertainties that could delay the anticipated drilling schedule for the Development Wells and adversely affect future production from the Underlying Properties. Any such delays or reductions in production could decrease future revenues that are available for distribution to unitholders.

The drilling and completion of the Development Wells are subject to numerous risks beyond SandRidge's and the trust's control, including risks that could delay the current drilling schedule for the Development Wells and the risk that drilling will not result in commercially viable oil, natural gas and natural gas liquids production. Drilling for oil, natural gas and natural gas liquids can be unprofitable if dry wells are drilled and if productive wells do not produce sufficient revenues to return a profit. SandRidge's and third-party operators' decisions to develop or otherwise exploit certain areas within the AMI will 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 costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. There can be no assurance that a Development Well that is successfully completed will pay out the capital costs spent to drill it. Drilling and production operations on the Underlying Properties 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;
- 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 and natural gas liquids water or drilling fluids;

natural disasters;

environmental hazards, such as oil, natural gas and natural gas liquids leaks, pipeline ruptures and discharges of toxic gases or fluids;

adverse weather conditions such as extreme cold, fires caused by extreme heat or lack of rain, and severe storms or tornadoes;

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- reductions in oil, natural gas and natural gas liquids prices;
- oil and natural gas property title problems; and
- market limitations for oil, natural gas and natural gas liquids.

In the event that drilling of Development Wells is delayed or the Producing Wells or Development Wells have lower than anticipated production due to one of the factors above or for any other reason, cash distributions to unitholders may be reduced. In addition, wells drilled in the Permian Basin in the AMI typically produce a large volume of water, which requires the drilling of saltwater disposal wells. SandRidge's inability to drill these wells or otherwise dispose of the water produced from the Producing Wells and Development Wells in an efficient manner could delay production and therefore the trust's receipt of proceeds from the royalty interests.

Oil, natural gas and natural gas liquids prices fluctuate due to a number of factors that are beyond the control of the trust and SandRidge, and lower prices could reduce proceeds to the trust and cash distributions to unitholders.

The trust's reserves and quarterly cash distributions are highly dependent upon the prices realized from the sale of oil, natural gas and natural gas liquids. The markets for these commodities are very volatile. Oil, natural gas and natural gas liquids prices can fluctuate widely in response to a variety of factors that are beyond the control of the trust and SandRidge. These factors include, among others:

- regional, domestic and foreign supply, and perceptions of supply, of oil, natural gas and natural gas liquids;
- the price of foreign imports;
- U.S. and worldwide political and economic conditions;
- the level of demand, and perceptions of demand, for oil, natural gas and natural gas liquids;
- weather conditions and seasonal trends;
- anticipated future prices of oil, natural gas and natural gas liquids, 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;
- 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 2007 through 2010, the highest monthly NYMEX settled price was $140.00 per Bbl and the lowest was $41.68 per Bbl. For natural gas, from 2007 through 2010, the highest monthly NYMEX settled price was $13.35 per MMBtu and the lowest was $2.98 per MMBtu. In addition, the market price of oil and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil and natural gas for heating purposes during the winter season.

Lower oil, natural gas and natural gas liquids prices will reduce proceeds to which the trust is entitled and may ultimately reduce the amount of oil, natural gas and natural gas liquids that is economic to produce from the Underlying Properties. As a result, SandRidge or any third-party operator of any of the Underlying Properties could determine during periods of low oil, natural gas and natural gas liquids prices to shut in or curtail production from wells on the Underlying Properties. In addition, the operator of the

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Underlying Properties could determine during periods of low oil and natural gas prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, SandRidge or any third party operator may abandon any well or property if it reasonably believes that the well or property can no longer produce oil, natural gas and natural gas liquids in commercially economic quantities. This could result in termination of the portion of the royalty interest relating to the abandoned well or property, and SandRidge would have no obligation to drill a replacement well. The volatility of oil, natural gas and natural gas liquids prices also reduces the accuracy of target distributions to trust unitholders. For a discussion of certain risks related to the trust's hedging arrangements, see " The hedging arrangements for the trust will cover only a portion of the production attributable to the trust, and such arrangements will limit the trust's ability to benefit from commodity price increases for hedged volumes above the corresponding hedge price."

Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the trust and the value of the trust units.

The value of the trust units and the amount of future cash distributions to the trust unitholders will depend upon, among other things, the accuracy of the future production estimated to be attributable to the trust's royalty interests. See "The Underlying Properties Oil, Natural Gas and Natural Gas Liquids Reserves" for a discussion of the method of allocating proved reserves to the trust. It is not possible to measure underground accumulations of oil, natural gas and natural gas liquids in an exact way, and estimating reserves is inherently uncertain. Ultimately, actual production and revenues for the Underlying Properties could be materially less than estimated amounts. Petroleum engineers are required to make subjective estimates of underground accumulations of oil, natural gas and natural gas liquids based on factors and assumptions that include:

- historical production from the area compared with production rates from other producing areas;
- oil, natural gas and natural gas liquids prices, production levels, Btu content, production expenses, transportation costs, severance and excise taxes and capital expenditures; and
- the assumed effect of governmental regulation.

Changes in these assumptions or actual production costs incurred and results of actual development could materially decrease reserve estimates. As with all drilling programs, there is a risk that the quality of the target reservoir is less than that assumed for purposes of the reserve report. As a result, you may not receive the benefit of the total amount of proved undeveloped reserves reflected in the reserve report, notwithstanding the fact that SandRidge has satisfied its drilling obligation. See "Summary The Development Wells."

In certain circumstances the trust may have to make cash payments under the hedging arrangements and these payments could be significant.

If actual production is below the amounts forecast in the reserve report and oil or natural gas prices rise, the hedging arrangements entered into by the trust may result in the trust having to make cash payments under the hedging arrangements which could, in certain circumstances, be significant. Swap contracts underlying the derivatives agreement between SandRidge and the trust and swap contracts entered into between the trust and unaffiliated hedge counterparties provide the trust with the right to receive from SandRidge or the hedge counterparties, as applicable, the excess of the fixed price specified in the hedge contract over a floating market price, multiplied by the volume of production hedged. If the floating market price exceeds the specified fixed price, the trust must pay SandRidge or its hedge counterparties, as applicable, this difference in price multiplied by the volume of production hedged, even if the production attributable to the trust's royalty interests is insufficient to cover the volume of production specified in the applicable hedge contracts. Accordingly, if the production attributable to the trust's royalty interests is less than the volume hedged and the floating market price exceeds the specified fixed price, the trust will have to make payments against which it will have insufficient offsetting cash receipts from the sale of production attributable to its royalty interests. Furthermore, if one or more of the purchasers of the production attributable to the Underlying Properties defaults on a payment obligation, the trust may have insufficient cash receipts to make payments under the hedging arrangements. If these payments become too large, the trust's liquidity and cash available for distribution may be adversely affected. In addition, the trust's obligations to the counterparties under its direct hedge contracts will be secured by a first priority lien on the trust's existing and future royalty interests in the Underlying Properties. If the trust fails to make any required payments to its unaffiliated hedge counterparties, these counterparties will have a right to foreclose on the trust's royalty interests and may sell the trust's royalty interests in order to satisfy the trust's payment obligations. Please see "The Trust Hedging Arrangements" for more details on the prices and production volumes associated with the trust's hedging arrangements.

Estimates of the target distributions to unitholders, subordination thresholds and incentive thresholds are based on assumptions that are inherently subjective and are subject to significant business, economic, financial, legal, regulatory and competitive risks and uncertainties that could cause actual cash distributions to differ materially from those estimated.

The estimates of target distributions to unitholders, subordination thresholds and incentive thresholds, as set forth in this prospectus, are based on SandRidge's calculations, and SandRidge has not received an opinion or report on such calculations from any independent accountants, financial advisers, or engineers. Such calculations are based on assumptions about drilling, production, oil, natural gas and natural gas liquids prices, hedging activities, capital expenditures, expenses, tax rates and production tax credits under state law and other matters that are inherently uncertain and are subject to significant business, economic, financial, legal, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those estimated. For example, these estimates have assumed that oil, natural gas and natural gas liquids production is sold at prices consistent with settled NYMEX pricing for April through June 2011, monthly NYMEX forward pricing as of July 15, 2011 for the remainder of the period ending March 31, 2014, and assumed price increases after March 31, 2014 of 2.5% annually, capped at $120.00 per Bbl of oil in 2023 and $7.00 per MMBtu of natural gas in 2022; however, actual sales prices may be significantly lower. Additionally, these estimates assume that the Development Wells will be drilled on SandRidge's current anticipated schedule and the related Underlying Properties will achieve production volumes set forth in the reserve report; however, the drilling of the Development Wells may be delayed and actual production volumes may be significantly lower. Further, after wells are completed, production operations may be curtailed, delayed or terminated as a result of a variety of risks and uncertainties, including those described above under " Drilling for and producing oil, natural gas and natural gas liquids on the Underlying Properties are high risk activities with many uncertainties that could delay the anticipated drilling schedule for the Development Wells and adversely affect future production from the Underlying Properties. Any such delays or reductions in production could decrease future revenues that are available for distribution to unitholders."

Furthermore, neither the target distribution nor the subordination threshold for each quarter during the subordination period necessarily represents the actual cash distributions you will receive. To the extent actual production volumes or sales prices of oil, natural gas and natural gas liquids differ from the assumptions used to generate the target distributions, the actual distributions you receive may be lower than the target distribution and the subordination threshold for the applicable quarter. A cash distribution to trust unitholders below the target distribution amount or the subordination threshold may materially adversely affect the market price of the trust units.

The subordination of certain trust units held by SandRidge does not assure that you will in fact receive any specified return on your investment in the trust.

Although SandRidge will not be entitled to receive any distribution on its subordinated units unless there is enough cash for all of the common units to receive a distribution equal to the subordination threshold for such quarter (which is 20% below the target distribution level for the corresponding quarter), the subordinated units constitute only a 25% interest in the trust, and this feature does not guarantee that common units will receive a distribution equal to the subordination threshold, or any distribution at all. Additionally, the subordination period will terminate and the subordinated units will convert into common units at the end of the fourth full calendar quarter following SandRidge's completion of its drilling obligation. Depending on the prices at which SandRidge is able to sell volumes attributable to the trust, the common units may receive a distribution that is below the subordination threshold.

Quarterly cash distributions will be made by the trust based on the proceeds received by the trust pursuant to the royalty interests for the preceding calendar quarter. If a quarterly cash distribution is lower than the target distribution amount or subordination threshold set forth in this prospectus for any quarter, the common units will not be entitled to receive any additional distributions nor will the units be entitled to arrearages in any future quarter.

The historical and pro forma financial information included in this prospectus may not be representative of the trust's future distributable income.

The historical financial information included in this prospectus is derived from Arena's and SandRidge's historical financial statements for periods prior to the trust's initial public offering. The historical statements of revenues and direct operating expenses of the Arena Properties included in this prospectus do not give effect to the terms and conditions of the royalty interests and, as a result, do not reflect what the trust's distributable income will be in the future. Further, the historical results of the Arena Properties and the historical results of operations of Arena Resources, Inc. reflect a substantially larger asset base than the Underlying Properties. In addition, for periods prior to 2010 the historical results of operations of Arena Resources, Inc. are presented and discussed on a consolidated basis and include all items of income and expense presented in a consolidated statement of operations, whereas the pro forma statements of revenues and direct operating expense for the portion of the Underlying Properties attributable to the royalty interests to be held by the trust exclude a number of items of income and expense applicable to consolidated statements of operations, such as general and administrative expenses, interest expense, depreciation, depletion and amortization, income taxes, and hedging items. For more information, please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting the Comparability of the Historical Financial Results of the Arena Properties or Arena Resources, Inc. to the Future Results of the Trust."

In preparing the pro forma statements of distributable income included in this prospectus, SandRidge has made adjustments to the historical pro forma financial information for the Underlying Properties based upon currently available information and upon assumptions that SandRidge and the trust believe are reasonable in order to reflect, on a pro forma basis, the impact of the conveyance of the royalty interests to the trust and the other items discussed in the unaudited pro forma financial statements and related notes. The estimates and assumptions used in the calculation of the pro forma financial information in this prospectus may be materially different from the trust's actual experience. Accordingly, the pro forma financial information included in this prospectus does not purport to represent what the trust's distributable income would actually have been had it been in operation during the periods presented or what the trust's distributable income will be in the future, nor does the pro forma financial information give effect to any events other than those discussed in the unaudited pro forma financial statements and related notes.

Shortages or increases in costs of equipment, services and qualified personnel could delay the drilling of the Development Wells and result in a reduction in the amount of cash available for distribution.

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, natural gas and natural gas liquids 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, natural gas and natural gas liquids 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 hinder SandRidge's ability to perform the drilling obligation and delay completion of the Development Wells, which would reduce future distributions to trust unitholders.

Due to the trust's lack of industry and geographic diversification, adverse developments in the trust's existing area of operation could adversely impact its financial condition, results of operations and cash flows and reduce its ability to make distributions to the unitholders.

The Underlying Properties will be operated for oil, natural gas and natural gas liquids production only and are focused exclusively in the Permian Basin in Andrews County, Texas. This concentration could disproportionately expose the trust's interests to operational and regulatory risk in that area. Due to the lack of diversification in industry type and location of the trust's interests, adverse developments in the oil, natural gas and natural gas liquids market or the area of the Underlying Properties, including, for example, transportation or treatment capacity constraints, curtailment of production or treatment plan closures for scheduled maintenance, could have a significantly greater impact on the trust's financial condition, results of operations and cash flows than if the trust's royalty interests were more diversified.

The generation of proceeds for distribution by the trust depends in part on access to and the operation of gathering, transportation and processing facilities. Any limitation in the availability of those facilities could interfere with sales of oil, natural gas and natural gas liquids production from the Underlying Properties.

The amount of oil, natural gas and natural gas liquids that may be produced and sold from any well to which the Underlying Properties relate is subject to curtailment in certain circumstances, such as by reason of weather conditions, pipeline interruptions due to scheduled and unscheduled maintenance, failure of tendered oil, natural gas and natural gas liquids to meet quality specifications of gathering lines or downstream transporters, excessive line pressure which prevents delivery, physical damage to the gathering system or transportation system or lack of contracted capacity on such systems. The curtailments may vary from a few days to several months. In many cases, SandRidge is provided limited notice, if any, as to when production will be curtailed and the duration of such curtailments. If SandRidge is forced to reduce production due to such a curtailment, the revenues of the trust and the amount of cash distributions to the trust unitholders would similarly be reduced due to the reduction of proceeds from the sale of production. Although SandRidge currently does not have any material production shut-in and does not shut-in production on a routine basis as a result of lack of accessibility to transportation or lack of processing facilities, there can be no assurance this will be the case in the future.

Some of the Development Wells on the Underlying Properties may be drilled in locations that currently are not serviced by natural gas gathering and transportation pipelines or locations in which existing gathering and transportation pipelines do not have sufficient capacity to transport additional production. As a result, SandRidge may not be able to sell the natural gas production from certain Development Wells until the necessary gathering systems and/or transportation pipelines are constructed or until the necessary transportation capacity on an interstate pipeline is obtained. In particular, the system SandRidge intends to use to compress and process the natural gas produced from certain of the Underlying Properties could be near its capacity and may not be able to process all of SandRidge's gas.

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Any delay in the expansion of such system or the construction or expansion of any other natural gas gathering systems beyond the currently estimated construction schedules, or a delay in the procurement of additional transportation capacity would delay the receipt of any proceeds that may be associated with the natural gas production from the Development Wells.

The trust units may lose value as a result of title deficiencies with respect to the Underlying Properties.

The existence of title deficiencies with respect to the Underlying Properties could reduce the value or render properties worthless, thus adversely affecting the distributions to unitholders. SandRidge does not obtain title insurance covering oil, gas and mineral leaseholds. Additionally, undeveloped leasehold acreage has greater risk of title defects than developed acreage.

SandRidge has not necessarily obtained drilling title opinions on all of the Underlying Properties. Frequently, as a result of title examinations, certain curative work may be required to correct identified title defects, and such curative work entails time and expense. SandRidge's inability or failure to cure title defects could render some locations undrillable or cause SandRidge to lose its rights to some or all production from some of the Underlying Properties, which could result in a reduction in proceeds available for distribution to unitholders and the value of the trust units if a comparable additional location to drill a Development Well cannot be identified.

The trust is passive in nature and will have no stockholder voting rights in SandRidge, managerial, contractual or other ability to influence SandRidge, or control over the field operations of, sale of oil, natural gas and natural gas liquids from, or development of, the Underlying Properties.

Trust unitholders have no voting rights with respect to SandRidge and, therefore, will have no managerial, contractual or other ability to influence SandRidge's activities or operations of the Underlying Properties. In addition, some of the Development Wells may be operated by third parties unrelated to SandRidge. Such third party operators may not have the operational expertise of SandRidge within the AMI. Oil, natural gas and natural gas liquids properties are typically managed pursuant to an operating agreement among the working interest owners in the properties. The typical operating agreement contains procedures whereby the owners of the aggregate working interest in the property designate one of the interest owners to be the operator of the property. Under these arrangements, the operator is typically responsible for making all decisions relating to drilling activities, sale of production, compliance with regulatory requirements and other matters that affect the property. Neither the trustee nor the trust unitholders has any contractual ability to influence or control the field operations of, sale of oil, natural gas and natural gas liquids from, or future development of, the Underlying Properties.

The oil, natural gas and natural gas liquids reserves estimated to be attributable to the Underlying Properties of the trust are depleting assets and production from those reserves will diminish over time. Furthermore, the trust is precluded from acquiring other oil and gas properties or royalty interests to replace the depleting assets and production.

The proceeds payable to the trust from the royalty interests are derived from the sale of the production of oil, natural gas and natural gas liquids from the Underlying Properties. The oil, natural gas and natural gas liquids reserves attributable to the Underlying Properties are depleting assets, which means that the reserves of oil, natural gas and natural gas liquids attributable to the Underlying Properties will decline over time. As a result, the quantity of oil, natural gas and natural gas liquids produced from the Underlying Properties will decline over time.

Future maintenance may affect the quantity of proved reserves that can be economically produced from the Underlying Properties to which the wells relate. The timing and size of these projects will depend on, among other factors, the market prices of oil, natural gas and natural gas liquids. With the exception of SandRidge's commitment to drill the Development Wells, SandRidge has no contractual obligation to make capital expenditures on the Underlying Properties in the future. Furthermore, for properties on which SandRidge is not designated as the operator, SandRidge has no control over the timing or amount of those capital expenditures. SandRidge also has the right to non-consent and not participate in the capital expenditures on properties for which it is not the operator, in which case SandRidge and the trust will not receive the production resulting from such capital expenditures. If SandRidge or other operators of the wells to which the Underlying Properties relate do not implement maintenance projects when warranted, the future rate of production decline of proved reserves may be higher than the rate currently expected by SandRidge or estimated in the reserve report.

The trust agreement will provide that the trust's business activities will generally be limited to owning the royalty interests and entering into the hedging arrangements and activities reasonably related thereto, including activities required or permitted by the terms of the conveyances related to the royalty interests. As a result, the trust will not be permitted to acquire other oil and gas properties or royalty interests to replace the depleting assets and production attributable to the trust.

An increase in the differential between the price realized by SandRidge for oil, natural gas and natural gas liquids produced from the Underlying Properties and the NYMEX or other benchmark price of oil or natural gas could reduce the proceeds to the trust and therefore the cash distributions by the trust and the value of trust units.

The prices received for SandRidge's oil, natural gas and natural gas liquids production usually fall below benchmark prices such as NYMEX. The difference between the price received and the benchmark price is called a differential. The amount of the differential will depend on a variety of factors, including discounts based on the quality and location of hydrocarbons produced, Btu content and post-production costs. These factors can cause differentials to be volatile from period to period. SandRidge has little or no control over the factors that determine the amount of the differential, and cannot accurately predict natural gas or crude oil differentials. Increases in the differential between the realized price of oil, natural gas and natural gas liquids and the benchmark price for oil, natural gas and natural gas liquids could reduce the proceeds to the trust and therefore the cash distributions by the trust and the value of the trust units. The target distributions were prepared using (a) for natural gas, an assumed negative differential of 28% from NYMEX futures prices for natural gas, (b) for oil, an assumed negative differential of $4.27 from NYMEX futures prices for oil and (c) for natural gas liquids, an assumed negative differential of 51.65% from NYMEX futures prices for oil. For more information on the differentials assumed for purposes of preparing the target distributions, see "Target Distributions and Subordination and Incentive Thresholds Significant Assumptions Used to Calculate the Target Distributions."

The amount of cash available for distribution by the trust will be reduced by post-production costs and applicable taxes associated with the trust's royalty interests, trust expenses and incentive distributions payable to SandRidge.

The royalty interests and the trust will bear certain costs and expenses that will reduce the amount of cash received by or available for distribution by the trust to the holders of the trust units. These costs and expenses include the following:

- the trust's share of the costs incurred by SandRidge to gather, store, compress, transport, process, treat, dehydrate and market the oil and gas;
- the trust's share of applicable taxes on the oil and gas;
- trust administrative expenses, including fees paid to the trustee and the Delaware trustee, the annual administrative services fee payable to SandRidge, tax return and Schedule K-1 preparation and mailing costs, independent auditor fees and registrar and transfer agent fees, and costs associated with annual and quarterly reports to unitholders; and
- the trust's liability for Texas franchise tax.

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In addition, the amount of funds available for distribution to unitholders will be reduced by the amount of any cash reserves maintained by the trustee in respect of anticipated future trust administrative expenses.

Further, during the subordination period, SandRidge will be entitled to receive a quarterly incentive distribution from the trust equal to 50% of the amount by which cash available to be paid to all unitholders exceed the incentive threshold for the applicable quarter. See "Target Distributions and Subordination and Incentive Thresholds."

The amount of costs and expenses borne by the trust may vary materially from quarter-to-quarter. The extent by which the costs and expenses of the trust are higher or lower in any quarter will directly decrease or increase the amount received by the trust and available for distribution to the unitholders. For a further summary of post-production costs and applicable taxes for the producing lives of the Producing Wells and Development Wells, see "The Underlying Properties." Historical post-production costs and taxes, however, may not be indicative of future post-production costs and taxes.

The hedging arrangements for the trust will cover only a portion of the production attributable to the trust, and such arrangements will limit the trust's ability to benefit from commodity price increases for hedged volumes above the corresponding hedge price.

The trust will enter into oil hedge contracts with unaffiliated counterparties. Additionally, pursuant to the derivatives agreement, SandRidge will provide the trust with the effect of certain oil hedge contracts that it plans to enter into with third parties. Under the combined hedging arrangements, approximately 73% of the expected production and approximately 79% of the expected revenues upon which the target distributions are based from August 1, 2011 through March 31, 2015 will be hedged. The remaining estimated production of oil during that time, all production of natural gas and natural gas liquids during that time, and all production after such time will not be hedged. With respect to unhedged volumes and periods, the trust will not be protected against the price risks inherent in holding interests in oil, a commodity that is frequently characterized by significant price volatility. Furthermore, while the use of hedging arrangements limits the downside risk of price declines, they may also limit the trust's ability to benefit from increases in oil prices above the hedge price on the portion of the production attributable to the trust's royalty interests that is hedged.

The trust's receipt of any payments due to it based on the trust's hedge contracts with unaffiliated hedge counterparties and the derivatives agreement with SandRidge depends upon the financial position of the trust's unaffiliated hedging counterparties, SandRidge and SandRidge's hedging counterparties. The trust's counterparties under its hedge contracts with unaffiliated third parties will be institutions with a corporate credit rating of at least A/A2 as rated by Standard & Poor's or Moody's, including Morgan Stanley Capital Group Inc., J. Aron & Company, an affiliate of Goldman, Sachs & Co., and Barclays Bank PLC. The trust's counterparty under the derivatives agreement is SandRidge, whose counterparties will also be institutions with a corporate credit rating of at least A/A2, including Morgan Stanley Capital Group Inc., J. Aron & Company, an affiliate of Goldman, Sachs & Co., and Barclays Bank PLC. In the event that any of the counterparties to the oil and natural gas hedge contracts default on their obligations to make payments under such contracts, the cash distributions to the trust unitholders would likely be materially reduced as the hedge payments are intended to provide additional cash to the trust during periods of lower oil and natural gas prices. SandRidge will not be required to make payments to the trust under the derivatives agreement to the extent of payment defaults by SandRidge's hedge contract counterparties. Following this offering, except in limited circumstances involving the restructuring of an existing hedge, the trust will have no ability to terminate its hedge contracts or enter into additional hedges of its own. See " SandRidge's ability to satisfy its obligations to the trust depends on its financial position, and in the event of a default by SandRidge in its obligation to drill the Development Wells, or in the event of SandRidge's bankruptcy, it may be expensive and time-consuming for the trust to exercise its remedies."

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For Development Wells drilled on properties where SandRidge is not the operator, SandRidge will rely on third party operators to drill the Development Wells, and for Development Wells where SandRidge is the operator, SandRidge may rely on third party servicers to conduct the drilling operations.

SandRidge owns a majority working interest in substantially all of the locations on which it expects to drill the Development Wells, and it expects to operate such wells during the subordination period. For Development Wells drilled on properties where SandRidge is not the operator, however, SandRidge will rely on third party operators to drill the Development Wells. In addition, where SandRidge is the operator of a Development Well, it may rely on third party servicers to perform the necessary drilling operations. The ability of third-party operators to help SandRidge meet the drilling obligation, and the ability of third-party servicers to perform drilling operations for SandRidge, will depend on those operators' future financial condition and economic performance and access to capital, which, in turn, will depend upon the supply and demand for oil, natural gas and natural gas liquids, prevailing economic conditions and financial, business and other factors. The failure of a third-party operator to adequately perform operations could delay drilling or completion of wells, or reduce production from the Underlying Properties and the cash available for distribution to trust unitholders. SandRidge may be provided little or no notice by these operators that they are failing to drill the Development Wells in accordance with pre-existing schedules. If the Development Wells take longer to be drilled and completed than currently anticipated, this may delay revenue earned from the production of oil, natural gas and natural gas liquids by such wells. The revenues distributable to the trust and the amount of cash distributable to the trust unitholders would similarly be delayed.

Production of oil, natural gas and natural gas liquids on the Underlying Properties could be materially and adversely affected by severe or unseasonable weather.

Production of oil, natural gas and natural gas liquids on the Underlying Properties could be materially and adversely affected by severe weather. Repercussions of severe weather conditions may include:

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

The trustee may, under certain circumstances, sell the royalty interests and dissolve the trust. The trust will begin to liquidate following the end of the 20-year period in which the trust is in existence.

The royalty interests will be sold and the trust will be dissolved upon the occurrence of certain events. For example, the trustee must sell the royalty interests if unitholders approve the sale or vote to dissolve the trust. The trustee must also sell the royalty interests if cash available for distribution for any four consecutive quarters, on a cumulative basis, is less than $5.0 million. The sale of all of the royalty interests will result in the dissolution of the trust. Upon the dissolution of the trust, the net proceeds of any such sale will be distributed to the trust unitholders in accordance with their interests and unitholders will not be entitled to receive any proceeds from the sale of production from the Underlying Properties following such date.

At the Termination Date, 50% of the PDP Royalty Interest and 50% of the Development Royalty Interest will automatically revert to SandRidge, while the remaining 50% of the PDP Royalty Interest and 50% of the Development Royalty Interest will be sold and the proceeds will be distributed to the unitholders (including SandRidge to the extent of any trust units it owns) at the Termination Date or soon thereafter. The price received by the trust by any purchaser of the remaining royalty interests will depend, among other things, on the prices of oil, natural gas and natural gas liquids at that time. There can be no assurance that the prices of oil, natural gas and natural gas liquids will be at levels such that trust unitholders will receive any particular amount of cash in return for the trust's sale of such royalty interests. Moreover, SandRidge will have a right of first refusal to purchase such royalty interests at the Termination Date, which may reduce the inclination of third parties to place a bid, and thereby reduce the value received by the trust in a sale. If the trustee receives a bid from a proposed purchaser other than SandRidge and wants to sell all or part of the remaining royalty interests to such third party, the trustee will be required to give notice to SandRidge and identify the proposed purchaser and proposed sale price, and other terms of the bid. See "The Trust."

There has been no public market for the common units and no independent appraisal of the value of the royalty interests has been performed.

The initial public offering price of the common units will be determined by negotiation among SandRidge and the underwriters. Among the factors to be considered in determining the initial public offering price, in addition to prevailing market conditions, will be current and historical oil, natural gas and natural gas liquids prices, current and prospective conditions in the supply and demand for oil, natural gas and natural gas liquids, reserve and production quantities estimated for the royalty interests and the trust's cash distributions prospects. None of SandRidge, the trust or the underwriters will obtain any independent appraisal or other opinion of the value of the royalty interests other than the reserve report prepared by Netherland Sewell.

The trust is managed by a trustee who cannot be replaced except at a special meeting of trust unitholders.

The business and affairs of the trust will be managed by the trustee. Your voting rights as a trust unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of trust unitholders or for an annual or other periodic re-election of the trustee. The trust agreement provides that the trustee may only be removed and replaced by the holders of a majority of the outstanding trust units, excluding trust units held by SandRidge voting in person or by proxy at a special meeting of trust unitholders at which a quorum is present called by either the trustee or the holders of not less than 10% of the outstanding trust units. As a result, it may be difficult for public unitholders to remove or replace the trustee without the cooperation of holders of a substantial percentage of the outstanding trust units.

Trust unitholders have limited ability to enforce provisions of the royalty interests, and SandRidge's liability to the trust is limited.

The trust agreement permits the trustee and the trust to sue SandRidge or any other future owner of the Underlying Properties to enforce the terms of the conveyances creating the PDP Royalty Interest and the Development Royalty Interest. If the trustee does not take appropriate action to enforce provisions of these conveyances, a trust unitholder's recourse would be limited to bringing a lawsuit against the trustee to compel the trustee to take specified actions. The trust agreement expressly limits a trust unitholder's ability to directly sue SandRidge or any other party other than the trustee. As a result, trust unitholders will not be able to sue SandRidge or any future owner of the Underlying Properties to enforce the trust's rights under the conveyances. Furthermore, the royalty interest conveyances provide that, except as set forth in the conveyances, SandRidge will not be liable to the trust for the manner in which it performs its duties in operating the Underlying Properties as long as it acts in good faith and, to the fullest extent permitted by law, will owe no fiduciary duties to the trust or the unitholders.

Courts outside of Delaware may not recognize the limited liability of the trust unitholders provided under Delaware law.

Under the Delaware Statutory Trust Act, trust unitholders will be entitled to the same limitation of personal liability extended to stockholders of private corporations for profit under the General Corporation Law of the State of Delaware. No assurance can be given, however, that the courts in jurisdictions outside of Delaware will give effect to such limitation.

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SandRidge may sell trust units in the public or private markets, and such sales could have an adverse impact on the trading price of the common units.

After the closing of the offering, SandRidge will hold an aggregate of 9,375,000 common units and 13,125,000 subordinated units. All of the subordinated units will automatically convert into common units at the end of the subordination period. SandRidge has agreed not to sell any trust units for a period of 180 days after the date of this prospectus without the consent of Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC and Wells Fargo Securities, LLC, acting as representatives of the several underwriters. See "Trust Units Eligible for Future Sale SandRidge Lock-up Agreement." After such period, SandRidge may sell trust units in the public or private markets, and any such sales could have an adverse impact on the price of the common units or on any trading market that may develop. The trust has granted registration rights to SandRidge, which, if exercised, would facilitate sales of common units by SandRidge to the public. See "Trust Units Eligible for Future Sale Registration Rights Agreement."

Conflicts of interest could arise between SandRidge and the trust unitholders.

As a working interest owner in the Underlying Properties, SandRidge could have interests that conflict with the interests of the trust and the trust unitholders. For example:

- Notwithstanding its drilling obligation to the trust, SandRidge's interests may conflict with those of the trust and the trust unitholders in situations involving the development, maintenance, operation or abandonment of the Underlying Properties. Additionally, SandRidge may, consistent with its obligation to act as a reasonably prudent operator, abandon a well that is uneconomic, or not generating revenues from production in excess of its operating costs, even though such well is still generating revenue for the trust unitholders. Subsequent to fulfilling its drilling obligation, SandRidge may make decisions with respect to expenditures and decisions to allocate resources on projects in other areas that adversely affect the Underlying Properties, including reducing expenditures on these properties, which could cause oil, natural gas and natural gas liquids production to decline at a faster rate and thereby result in lower cash distributions by the trust in the future.

- SandRidge may sell some or all of the Underlying Properties, subject to its obligation not to sell any property relating to the Development Royalty Interest prior to satisfying its obligation to drill the Development Wells. Such sale may not be in the best interests of the trust unitholders. Any purchaser may lack SandRidge's experience in the Permian Basin or its creditworthiness.

- In connection with the sale by SandRidge of some or all of the Underlying Properties, SandRidge may require the trust to release for sale royalty interests with an aggregate value to the trust of up to $5.0 million during any 12-month period. These releases will be made conditional upon the trust receiving an amount equal to the fair value to the trust of such royalty interests, but will not require the consent of the trust unitholders. See "The Underlying Properties Sale and Abandonment of the Underlying Properties."

- SandRidge is permitted under the conveyance agreements creating the royalty interests to enter into new processing and transportation contracts without obtaining bids from or otherwise negotiating with any independent third parties, and SandRidge will deduct from the trust's proceeds any charges under such contracts attributable to production from the trust properties. Provisions in the conveyance agreements, however, require that charges under future contracts with affiliates of SandRidge relating to processing or transportation of oil, natural gas and natural gas liquids be comparable to charges prevailing in the area for similar services.

- After expiration of a 180-day lock-up period, SandRidge can sell its units regardless of the effects such sale may have on common unit prices or on the trust itself. Additionally, SandRidge can vote its trust units in its sole discretion.

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In addition, SandRidge has agreed that, if at any time the trust's cash on hand (including available cash reserves) is not sufficient to pay the trust's ordinary course administrative expenses as they become due, SandRidge will loan funds to the trust necessary to pay such expenses. Any such loan will be on an unsecured basis, and the terms of such loan will be substantially the same as those which would be obtained in an arms' length transaction between SandRidge and an unaffiliated third party. If SandRidge provides such funds to the trust, it would become a creditor of the trust and its interests as a creditor could conflict with the interests of unitholders. Finally, as hedge manager to the trust, SandRidge will have the ability to negotiate the terms of any novation, assignment or transfer of any hedge contract to which it is a party to the trust.

SandRidge may sell all or a portion of the Underlying Properties, subject to and burdened by the royalty interests, after satisfying its drilling obligation to the trust; any such purchaser could have a weaker financial position and/or be less experienced in oil, natural gas and natural gas liquids development and production than SandRidge.

You will not be entitled to vote on any sale of the Underlying Properties if the Underlying Properties are sold subject to and burdened by the royalty interests and the trust will not receive any proceeds from any such sale. The purchaser would be responsible for all of SandRidge's obligations relating to the royalty interests on the portion of the Underlying Properties sold, and SandRidge would have no continuing obligation to the trust for those properties. Additionally, SandRidge may enter into farmout or joint venture arrangements with respect to the wells burdened by the trust's royalty interest. Any purchaser, farmout counterparty or joint venture partner could have a weaker financial position and/or be less experienced in oil, natural gas and natural gas liquids development and production than SandRidge.

SandRidge's ability to satisfy its obligations to the trust depends on its financial position, and in the event of a default by SandRidge in its obligation to drill the Development Wells, or in the event of SandRidge's bankruptcy, it may be expensive and time-consuming for the trust to exercise its remedies.

Pursuant to the terms of the development agreement, SandRidge will be obligated to drill, or cause to be drilled, the Development Wells at its own expense. SandRidge owns a majority working interest in substantially all of the locations on which it expects to drill the Development Wells, and it expects to operate such wells until completion of its drilling obligation. SandRidge is also the operator of all of the Producing Wells. The conveyances provide that SandRidge will be obligated to market, or cause to be marketed, the oil, natural gas and natural gas liquids production related to the Underlying Properties. Additionally, SandRidge will be the counterparty to the trust's derivatives agreement and will have certain obligations to the trust under the agreement. In the event that SandRidge defaults on its obligation to make payments under the derivatives agreement, the cash distributions to the trust unitholders may be materially reduced as these payments are intended to provide additional cash to the trust during periods of lower oil, natural gas and natural gas liquids prices. Due to the trust's reliance on SandRidge to fulfill these numerous obligations, the value of the trust's royalty interest and its ultimate cash available for distribution will be highly dependent on SandRidge's performance.

SandRidge's ability to perform these obligations will depend on its future financial condition and economic performance and access to capital, which in turn will depend upon the supply and demand for oil, natural gas and natural gas liquids, prevailing economic conditions and financial, business and other factors, many of which are beyond SandRidge's control. See "SandRidge Energy, Inc." and "Where You Can Find More Information" for additional information relating to SandRidge.

In the event that SandRidge defaults on its obligation to drill the Development Wells, the trust would be able to foreclose on the Drilling Support Lien to the extent of SandRidge's remaining interests in the undeveloped portions of the AMI. The maximum amount the trust can recover in such a foreclosure action is approximately $295 million, which amount will be reduced proportionately as each Development Well is drilled. There can be no assurance that the value of SandRidge's interests in the undeveloped portions of

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the AMI secured by the Drilling Support Lien will be equal to the amount recoverable at any given time, and such interests may be worth considerably less. The process of foreclosing on such collateral may be expensive and time-consuming and delay the drilling and completion of the Development Wells; such delays and expenses would reduce trust distributions by reducing the amount of proceeds available for distribution. Any amounts actually recovered in a foreclosure action would be applied to completion of SandRidge's drilling obligation, would not result in any distribution to the trust unitholders and may be insufficient to drill the number of wells needed for the trust to realize the full value of the Development Royalty Interest. Furthermore, the trust would have to seek a new party to perform the drilling and operations of the wells. The trust may not be able to find a replacement driller or operator, and it may not be able to enter into a new agreement with such replacement party on favorable terms within a reasonable period of time.

SandRidge will not be required to maintain a segregated account for proceeds payable to the trust. The proceeds of the royalty interests may be commingled with proceeds of SandRidge's retained interest in the Underlying Properties for the period of time between SandRidge's sale of production attributable to the trust's royalty interests and the quarterly payment to the trust of its share of proceeds. It is possible that the trust may not have adequate facts to trace its entitlement to funds in the commingled pool of funds and that other persons may, in asserting claims against SandRidge's retained interest, be able to assert claims to the proceeds that should be delivered to the trust. If there is an event of default under SandRidge's credit facility, SandRidge must keep its accounts with banks that enter into control agreements with the administrative agent under the credit facility, which would permit the administrative agent to direct payment of funds in such accounts during the pendency of an event of default. In addition, during any bankruptcy of SandRidge, it is possible that payments of the royalties may be delayed or deferred. During the pendency of any SandRidge bankruptcy proceedings, the trust's ability to foreclose on the Drilling Support Lien, and the ability to collect cash payments being held in SandRidge's accounts that are attributable to production from the trust properties, may be stayed by the bankruptcy court. Delay in realizing on the collateral for the Drilling Support Lien is possible, and it cannot be guaranteed that a bankruptcy court would permit such foreclosure. It is possible that the bankruptcy would also delay the execution of a new agreement with another driller or operator. If the trust enters into a new agreement with a drilling or operating partner, the new partner might not achieve the same levels of production or sell oil, natural gas and natural gas liquids at the same prices as SandRidge was able to achieve.

Oil, natural gas and natural gas liquids wells are subject to operational hazards that can cause substantial losses. SandRidge maintains insurance; however, SandRidge may not be adequately insured for all such hazards.

There are a variety of operating risks inherent in oil, natural gas and natural gas liquids 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, natural gas and natural gas liquids at any of the Underlying Properties will reduce trust distributions by reducing the amount of proceeds available for distribution.

Additionally, if any of such risks or similar accidents occur, SandRidge 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 SandRidge experiences any of these problems, its ability to conduct operations and perform its obligations to the trust could be adversely affected. While SandRidge intends to obtain and maintain insurance coverage it deems appropriate for these risks with respect to the Underlying Properties, SandRidge's operations may result in liabilities exceeding such insurance coverage or liabilities not covered by insurance. If a well is damaged, SandRidge would have no obligation to drill a replacement well or make the trust whole for the loss.

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For more information on SandRidge's insurance coverage, please see "The Underlying Properties Insurance."

SandRidge 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 SandRidge to significant liabilities.

SandRidge's oil, natural gas and natural gas liquids 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, SandRidge must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. SandRidge 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, natural gas and natural gas liquids 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 level to restrict oil, natural gas and natural gas liquids drilling operations in certain locations. Any increased regulation or suspension of oil, natural gas and natural gas liquids 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 SandRidge's business, financial condition and results of operations. SandRidge must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent SandRidge 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, natural gas and natural gas liquids exploration and production may also affect production levels. SandRidge 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, natural gas and natural gas liquids 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, natural gas and natural gas liquids SandRidge can produce from its wells, limit the number of wells it can drill, or limit the locations at which it can conduct drilling operations, which in turn could negatively impact trust distributions, estimated and actual future net revenues to the trust and estimates of reserves attributable to the trust's interests.

New laws or regulations, or changes to existing laws or regulations may unfavorably impact SandRidge, could result in increased operating costs and have a material adverse effect on SandRidge's financial condition and results of operations. For example, Congress is currently considering legislation that, if adopted in its proposed form, would subject companies involved in oil, natural gas and natural gas liquids exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, the elimination of most U.S. federal tax incentives and deductions available to oil, natural gas and natural gas liquids exploration and production activities, and the prohibition or additional regulation of private energy commodity derivative and hedging activities.

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 SandRidge and third party downstream oil, natural gas and natural gas liquids transporters. These and other potential regulations could increase SandRidge's operating costs, reduce SandRidge's liquidity, delay SandRidge's operations, increase direct and third party post production costs associated with the trust's interests or otherwise alter the way SandRidge conducts its business, which could have a material adverse effect on SandRidge'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 SandRidge for transportation on downstream interstate pipelines.

The operations of SandRidge 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 oil, natural gas and natural gas liquids exploration and production operations of SandRidge in the Permian Basin are subject to stringent and comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to SandRidge'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; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency ("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 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 SandRidge's operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of SandRidge'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, SandRidge could be subject to joint and several strict liability for the removal or remediation of previously released materials or property contamination regardless of whether SandRidge was responsible for the release or contamination or if the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which SandRidge's wells are drilled and facilities where SandRidge'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 or property damage. In addition, the risk of accidental spills or releases could expose SandRidge to significant liabilities that could have a material adverse effect on its 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 SandRidge to make 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. SandRidge may not be able to recover some or any of these costs from insurance. As a result of the increased cost of compliance, SandRidge may decide to discontinue drilling. Additionally, permitting delays may inhibit SandRidge's ability to drill the Development Wells on schedule.

For more information on the environmental laws and regulations governing SandRidge's operations, please see "The Underlying Properties Regulation."

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil, natural gas and natural gas liquids that SandRidge produces while the physical effects of climate change could disrupt SandRidge's production and cause SandRidge to incur significant costs in preparing for or responding to those effects.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present a danger to public health and the environment. These findings allow the agency to adopt and implement regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Accordingly, the EPA has adopted regulations that require a reduction in emissions of GHGs from motor vehicles and also trigger permit review for GHG emissions from certain large stationary sources. The EPA's rules relating to emissions of GHGs from large 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 EPA from implementing, or requiring state environmental agencies to implement, the rules. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published a final rule that expands its October 2009 final rule on reporting of GHG emissions to require certain owners and operators of onshore oil, natural gas and natural gas liquids production to monitor greenhouse gas emissions beginning in 2011 and to report those emissions beginning in 2012. 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, SandRidge's equipment and operations could require SandRidge to incur costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil, natural gas and natural gas liquids that it produces. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate change 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 SandRidge's assets and operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect SandRidge's services.

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 recently asserted federal regulatory authority over certain hydraulic fracturing practices not currently employed by SandRidge in the AMI. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study anticipated to be available by late 2012 and final results by 2014. Also, for the second consecutive session, legislation has been introduced, but not adopted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For instance, in June 2011, Texas adopted a law that requires disclosure to the Railroad Commission of Texas of the additives and other chemicals contained in hydraulic fracturing fluids used in the state, subject to certain trade secret protections. If new laws or regulations that significantly restrict or regulate hydraulic fracturing are adopted, such legal requirements could make it more difficult or costly for SandRidge to perform fracturing to stimulate production from the Permian Basin and thereby affect the determination of whether a well is commercially viable. Restrictions on hydraulic fracturing could also reduce the amount of oil, natural gas and natural gas liquids that SandRidge is ultimately able to produce in commercial quantities from the Underlying Properties.

The trust will be subject to the requirements of the Sarbanes-Oxley Act of 2002, which may impose cost and operating challenges on it.

The trust will be subject to certain of the requirements of the Sarbanes-Oxley Act of 2002 which will require, among other things, maintenance by the trust of, and reports regarding the effectiveness of, a system of internal control over financial reporting. Complying with these requirements may pose operational challenges and may cause the trust to incur unanticipated expenses. Any failure by the trust to

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comply with these requirements could lead to a loss of public confidence in the trust's internal controls and in the accuracy of the trust's publicly reported results.

Tax Risks Related to the Units

The trust's tax treatment depends on its status as a partnership for U.S. federal income tax purposes. If the U.S. Internal Revenue Service ("IRS") were to treat the trust as a corporation for U.S. federal income tax purposes, then its cash available for distribution to unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the trust units depends largely on the trust being treated as a partnership for U.S. federal income tax purposes. The trust has not requested, and does not plan to request, a ruling from the Internal Revenue Service, or IRS, on this or any other tax matter affecting it.

It is possible in certain circumstances for a publicly traded trust otherwise treated as a partnership, such as the trust, to be treated as a corporation for U.S. federal income tax purposes. Although the trust does not believe based upon its current activities that it is so treated, a change in current law could cause it to be treated as a corporation for U.S. federal income tax purposes or otherwise subject it to taxation as an entity.

If the trust were treated as a corporation for U.S. federal income tax purposes, it would pay federal income tax on its taxable income at the corporate tax rate, which is currently a maximum of 35%. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you without first being subjected to taxation at the entity level. Because a tax would be imposed upon the trust as a corporation, its cash available for distribution to you would be substantially reduced. Therefore, treatment of the trust as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to the trust unitholders, likely causing a substantial reduction in the value of the trust units.

The trust agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects the trust to additional amounts of entity-level taxation for state or local income tax purposes, the subordination threshold amounts, incentive threshold amounts and target distribution amounts may be adjusted to reflect the impact of that law on the trust.

If the trust were subjected to a material amount of additional entity-level taxation by individual states, it would reduce the trust's cash available for distribution to unitholders.

Changes in current state law may subject the trust to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. For example, the trust will be required to pay Texas franchise tax each year at a maximum effective rate of .7% of its gross income apportioned to Texas in the prior year. This rate of tax is subject to change by new legislation at any time. Some portion of the revenues will be subject to the Texas franchise tax. Imposition of any similar taxes by any other state may substantially reduce the cash available for distribution to unitholders and, therefore, negatively impact the value of an investment in trust units.

The trust agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects the trust to additional amounts of entity-level taxation for state or local income tax purposes, the subordination threshold amounts, incentive threshold amounts and target distribution amounts may be adjusted to reflect the impact of that law on the trust.

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The tax treatment of an investment in trust units could be affected by recent and potential legislative changes, possibly on a retroactive basis.

The Health Care and Education Reconciliation Act of 2010 includes a provision that, in taxable years beginning after December 31, 2012, subjects an individual having adjusted gross income in excess of $200,000 (or $250,000 for married taxpayers filing joint returns) to an additional "Medicare tax" equal generally to 3.8% of the lesser of such excess or the individual's net investment income, which appears to include interest income and royalty income derived from investments such as the trust units as well as any net gain from the disposition of trust units. In addition, absent new legislation extending the current rates, beginning January 1, 2013, the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. Moreover, these rates are subject to change by new legislation at any time.

Current law may change so as to cause the trust to be treated as a corporation for U.S. federal income tax purposes or otherwise subject the trust to entity-level taxation. Specifically, the present U.S. federal income tax treatment of publicly traded partnerships, including the trust, or an investment in the trust units may be modified by administrative, legislative or judicial interpretation at any time. For example, at the federal level, legislation has been proposed in the past that would have eliminated partnership tax treatment for certain publicly traded partnerships. Although such legislation would not have applied to the trust as it was proposed, it could be reintroduced in a manner that does apply to the trust.

The trust agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects the trust to taxation as a corporation or otherwise subjects it to entity-level taxation for U.S. federal income tax purposes, the subordination threshold amounts, incentive threshold amounts and target distribution amounts may be adjusted to reflect the impact of that law on the trust.

The trust will adopt positions that may not conform to all aspects of existing Treasury Regulations. If the IRS contests the tax positions the trust takes, the value of the trust units may be adversely affected, the cost of any IRS contest will reduce the trust's cash available for distribution and income, gain, loss and deduction may be reallocated among trust unitholders.

If the IRS contests any of the U.S. federal income tax positions the trust takes, the value of the trust units may be adversely affected because the cost of any IRS contest will reduce the trust's cash available for distribution and income, gain, loss and deduction may be reallocated among trust unitholders. For example, the trust will generally prorate its items of income, gain, loss and deduction between transferors and transferees of the trust units each quarter based upon the record ownership of the trust units on the quarterly record date in such quarter instead of on the basis of the date a particular trust unit is transferred. Although simplifying conventions are contemplated by the Internal Revenue Code, and most publicly traded partnerships use similar simplifying conventions, the use of these methods may not be permitted under existing Treasury Regulations.

The trust has not requested a ruling from the IRS with respect to its treatment as a partnership for U.S. federal income tax purposes or any other matter affecting the trust. The IRS may adopt positions that differ from the conclusions of the trust's counsel expressed in this prospectus or from the positions the trust takes. It may be necessary to resort to administrative or court proceedings to attempt to sustain some or all of the conclusions of the trust's counsel or the positions the trust takes. A court may not agree with some or all of the conclusions of the trust's counsel or positions the trust takes. Any contest with the IRS may materially and adversely impact the market for the trust units and the price at which they trade. In addition, the trust's costs of any contest with the IRS will be borne indirectly by the trust unitholders because the costs will reduce the trust's cash available for distribution.

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You will be required to pay taxes on your share of the trust's income even if you do not receive any cash distributions from the trust.

Because the trust unitholders will be treated as partners to whom the trust will allocate taxable income that could be different in amount than the cash the trust distributes, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of the trust's taxable income even if you receive no cash distributions from the trust. You may not receive cash distributions from the trust equal to your share of the trust's taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of the trust units could be more or less than expected.

If you sell your trust units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those trust units. Because distributions in excess of your allocable share of the trust's net taxable income decrease your tax basis in your trust units, the amount, if any, of such prior excess distributions with respect to the trust units you sell will, in effect, become taxable income to you if you sell such trust units at a price greater than your tax basis in those trust units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion recapture. Please read "U.S. Federal Income Tax Considerations Disposition of Trust Units Recognition of Gain or Loss" for a further discussion of the foregoing.

The ownership and disposition of trust units by non-U.S. persons may result in adverse tax consequences to them.

Investment in trust units by non-U.S. persons raises issues unique to them. For example, distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons may be required to file U.S. federal income tax returns and pay tax on their share of the trust's taxable income or proceeds from the sale of trust units. If you are a non-U.S. person, you should consult a tax advisor before investing in the trust units.

The trust will treat each purchaser of trust units as having the same economic attributes without regard to the actual trust units purchased. The IRS may challenge this treatment, which could adversely affect the value of the trust units.

Due to a number of factors, including the trust's inability to match transferors and transferees of trust units, the trust will adopt positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely alter the tax effects of an investment in trust units. It also could affect the timing of tax benefits or the amount of gain from your sale of trust units and could have a negative impact on the value of the trust units or result in audit adjustments to your tax returns. Please read "U.S. Federal Income Tax Considerations Tax Consequences of Trust Unit Ownership Section 754 Election."

The trust will prorate its items of income, gain, loss and deduction between transferors and transferees of the trust units each quarter based upon the record ownership of the trust units on the quarterly record date in such quarter instead of on the basis of the date a particular trust unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among the trust unitholders.

The trust will generally prorate its items of income, gain, loss and deduction between transferors and transferees of the trust units based upon the record ownership of the trust units on the quarterly record date in such quarter instead of on the basis of the date a particular trust unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, the trust's counsel is unable to opine as to the validity of this method. If the IRS were to challenge the trust's

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proration method, the trust may be required to change its allocation of items of income, gain, loss and deduction among the trust unitholders and the costs to the trust of implementing and reporting under any such changed method may be significant. Please read "U.S. Federal Income Tax Considerations Disposition of Trust Units Allocations Between Transferors and Transferees."

A trust unitholder whose trust units are loaned to a "short seller" to cover a short sale of trust units may be considered as having disposed of those trust units. If so, he would no longer be treated for tax purposes as a partner with respect to those trust units during the period of the loan and may recognize gain or loss from the disposition.

Because a trust unitholder whose trust units are loaned to a "short seller" to cover a short sale of trust units may be considered as having disposed of the loaned trust units, he may no longer be treated for tax purposes as a partner with respect to those trust units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of the trust's income, gain, loss or deduction with respect to those trust units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those trust units could be fully taxable as ordinary income. The trust's counsel has not rendered an opinion regarding the treatment of a unitholder where trust units are loaned to a short seller to cover a short sale of trust units; therefore, trust unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from loaning their trust units.

The trust will adopt certain valuation methodologies that may affect the income, gain, loss and deduction allocable to the trust unitholders. The IRS may challenge this treatment, which could adversely affect the value of the trust units.

The U.S. federal income tax consequences of the ownership and disposition of trust units will depend in part on the trust's estimates of the relative fair market values, and the initial tax bases, of the trust's assets. Although the trust may from time to time consult with professional appraisers regarding valuation matters, the trust will make many of the relative fair market value estimates itself. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by trust unitholders might change, and trust unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

The sale or exchange of 50% or more of the trust's capital and profits interests during any twelve-month period will result in the termination of the trust's partnership status for U.S. federal income tax purposes.

The trust will be considered to have technically terminated for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in its capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same trust unit within any 12 month period will be counted only once. The trust's termination would, among other things, result in the closing of its taxable year for all trust unitholders, which would result in the trust filing two tax returns (and the trust unitholders could receive two Schedules K-1) for one calendar year. The IRS has recently announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be required to provide only a single Schedule K-1 to unitholders for the tax year in which the termination occurs. In the case of a unitholder reporting on a taxable year other than a calendar year ending December 31, the closing of the trust's taxable year may also result in more than 12 months of the trust's taxable income being includable in his taxable income for the year of termination. A technical termination would not affect the trust's classification as a partnership for U.S. federal income tax purposes, but instead, the trust would be treated as a new partnership for tax purposes. If treated as a new partnership, the trust

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must make new tax elections and could be subject to penalties if the trust is unable to determine that a technical termination occurred.

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

Among the proposed changes contained in President Obama's Budget Proposal for Fiscal Year 2012 is the elimination of certain key U.S. federal income tax preferences relating to oil, natural gas and natural gas liquids exploration and production. The President's budget proposes to eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. Specifically, the budget proposes to repeal the deduction for percentage depletion with respect to wells, including perpetual royalty interests in such wells, in which case only cost depletion would be available.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This prospectus and the documents incorporated by reference contain forward-looking statements. Such forward-looking statements are based on assumptions and beliefs that the trust and SandRidge believe to be reasonable; however, assumed facts almost always vary from actual results, and the differences between assumed facts and actual results can be material, depending upon the circumstances. Where the trust or SandRidge expresses an expectation or belief as to future results, that expectation or belief is expressed in good faith and based on assumptions believed to have a reasonable basis. It cannot be assured, however, that the stated expectation or belief will occur or be achieved or accomplished. All statements other than statements of historical facts included or incorporated by reference in this prospectus, including, without limitation, statements regarding the proved oil, natural gas and natural gas liquids reserves associated with the Underlying Properties, the trust's or SandRidge's future financial position, business strategy, budgets, pending acquisitions, recent acquisitions and divestitures, project costs and plans and objectives for future operations, including the information under the heading "Target Distributions and Subordination and Incentive Thresholds," statements pertaining to future development activities and costs, and other statements in this prospectus that are prospective and constitute forward-looking statements are forward-looking statements.

The words "estimate," "assume," "target," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "foresee," "plan," "goal," "should" and "intend" and similar expressions will generally identify forward-looking statements. Forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany those statements. In addition, neither the trust nor SandRidge undertakes an obligation to update or revise any forward-looking statements to reflect events or circumstances after the date of this prospectus.

With this in mind, you should consider the risks discussed under the heading "Risk Factors" in this prospectus, as well as those contained in SandRidge's Annual Report on Form 10-K for the year ended December 31, 2010 and its Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 and other disclosures about SandRidge that are included in or incorporated by reference into this prospectus.

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USE OF PROCEEDS

The trust is offering all of the common units to be sold in this offering. Assuming no exercise of the underwriters' over-allotment option, the estimated net proceeds of this offering will be approximately $502.6 million, after deducting underwriting discounts and commissions and offering expenses. The trust will deliver all of the net proceeds to one or more of SandRidge's wholly-owned subsidiaries as full consideration for the conveyance of the term royalty interests and, if applicable, as partial consideration for the conveyance of the perpetual royalty interests.

At the initial closing, 4,500,000 common units will be issued and retained by the trust and will be used to satisfy (if necessary) the over-allotment option granted to the underwriters. If the over-allotment option is exercised, the trust will sell to the underwriters such number of the retained units as is necessary to satisfy the over-allotment option, and will then deliver the net proceeds of such sale, together with any remaining unsold units, to one or more SandRidge subsidiaries as partial consideration for the conveyance of certain of the royalty interests. If the over-allotment option is not exercised by the underwriters, the retained units will be delivered to SandRidge subsidiaries, as partial consideration for the conveyance of certain of the royalty interests, promptly following the 30th day after the initial closing.

SandRidge intends to use the proceeds received from the offering to repay borrowings under its credit facility and for general corporate purposes, which may include the funding of the drilling obligation. Although SandRidge has no plans to immediately draw down a substantial amount under its credit facility, it expects to draw on the facility from time to time to fund its capital expenditures. As of June 30, 2011, the outstanding balance on SandRidge's credit facility, which matures in 2014, was approximately $80.0 million, and the weighted average interest rate of the credit facility was 2.44%. Borrowings under the credit facility in the past year were incurred by SandRidge for general corporate purposes, including to fund its capital expenditures. Affiliates of Morgan Stanley & Co. LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co., J.P. Morgan Securities LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc. and Wells Fargo Securities, LLC are lenders under the SandRidge credit facility being repaid with the offering proceeds being paid to SandRidge and will therefore receive a portion of the proceeds of the offering.

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SANDRIDGE ENERGY, INC.

SandRidge is a publicly traded, independent oil and natural gas company concentrating on development and production activities related to the exploitation of its significant holdings in West Texas and the Mid-Continent area of Oklahoma and Kansas. As of July 28, 2011, its market capitalization was approximately $4.8 billion, and as of December 31, 2010 it had total estimated net proved reserves of 545.9 MMBoe. SandRidge has approximately 210,000 net acres in the Permian Basin. SandRidge also owns and operates other interests in the Mississippian Formation, Mid-Continent, Cotton Valley Trend in East Texas, Gulf Coast and Gulf of Mexico. SandRidge also owns and operates gas gathering and processing facilities, CO_2 treating and transportation facilities, and drilling rig, oil field service and oil and gas marketing businesses.

SandRidge's principal executive offices are located at 123 Robert S. Kerr Avenue, Oklahoma City, Oklahoma 73102 and its telephone number is (405) 429-5500. Its website is *http://www.sandridgeenergy.com*.

The trust units do not represent interests in or obligations of SandRidge.

SandRidge's Experience With Prior Royalty Trusts

SandRidge has sponsored one prior royalty trust, SandRidge Mississippian Trust I (NYSE: SDT) (the "Mississippian Trust"), a publicly-traded trust that is similar to SandRidge Permian Trust. In connection with the formation of the Mississippian Trust, SandRidge conveyed royalty interests in specified oil and natural gas properties, limited to depths commonly known as the Mississippian formation, located in Alfalfa, Garfield, Grant, Major and Woods Counties in Oklahoma to the Mississippian Trust in exchange for trust units and the net proceeds of the Mississippian Trust's initial public offering. The terms of the royalty interests being conveyed in connection with the formation of SandRidge Permian Trust are similar to those of the royalty interests that were conveyed to the Mississippian Trust.

The Mississippian Trust completed its initial public offering on April 12, 2011. The net proceeds to the Mississippian Trust, before offering expenses of approximately $2.6 million, were approximately $338.7 million, and were delivered to SandRidge as partial consideration for the conveyance of royalty interests to the Mississippian Trust.

SandRidge owns 3,750,000 common units and 7,000,000 subordinated units in the Mississippian Trust, together representing an approximately 38.4% beneficial interest in the Mississippian Trust.

The Mississippian Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting the trust's administrative expenses, on or about 60 days following the completion of each quarter through (and including) the quarter ending December 31, 2030. On July 22, 2011, the Mississippian Trust declared a cash distribution of approximately $1.07 per unit covering production for the period from January 1, 2011 to May 31, 2011 for record holders as of August 15, 2011. The distribution will be paid on or about August 30, 2011.

Under a development agreement, SandRidge is obligated to drill, or cause to be drilled, a total of 123 development wells by December 31, 2014, the production from which will be subject to the royalty interests. In the event of delays, SandRidge will have until December 31, 2015 to fulfill its drilling obligation. A wholly owned subsidiary of SandRidge has granted to the Mississippian Trust a lien covering its interest in the area of mutual interest in which the trust underlying properties are located in order to secure the estimated amount of the drilling costs for the Mississippian Trust's interests in the undeveloped underlying properties (the "Drilling Support Lien"). The amount obtained by the Mississippian Trust pursuant to the Drilling Support Lien may not exceed $166.1 million. As SandRidge fulfills its drilling obligation over time, the total amount that may be recovered will be proportionately reduced and the completed development wells will be released from the lien. As of June 30, 2011, seven development wells had been drilled and the maximum amount recoverable under the Drilling Support Lien had been reduced to $156.6 million.

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Under an administrative services agreement, the Mississippian Trust is required to pay SandRidge an annual administrative services fee of $200,000 for accounting, tax preparation, bookkeeping and informational services to be performed by SandRidge on behalf of the Mississippian Trust. The Mississippian Trust is also party to a derivatives agreement with SandRidge that provides the Mississippian Trust with the benefit of certain oil and natural gas derivative contracts previously entered into by SandRidge with third parties. The underlying commodity derivative contracts cover volumes of oil and natural gas production through December 31, 2015. Under this arrangement, SandRidge will pay the Mississippian Trust amounts it receives from its counterparties in accordance with the underlying contracts, and the Mississippian Trust will pay SandRidge any amounts that SandRidge is required to pay its counterparties under such contracts.

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THE TRUST

The trust is a statutory trust created under the Delaware Statutory Trust Act in May 2011. The business and affairs of the trust will be managed by The Bank of New York Mellon Trust Company, N.A., as trustee. In addition, the Corporation Trust Company will act as Delaware trustee of the trust. The Delaware trustee will have only minimal rights and duties as are necessary to satisfy the requirements of having a trustee in Delaware who will accept service of process on the trust under the Delaware Statutory Trust Act. Although SandRidge will operate substantially all of the Underlying Properties, SandRidge will have no ability to manage or influence the management of the trust (except through its limited voting rights as a holder of trust units and its limited ability to manage the hedging program) and, to the fullest extent permitted by law, will owe no fiduciary duties to the trust or the unitholders.

The trustee can authorize the trust to borrow money to pay trust administrative or incidental expenses that exceed cash held by the trust. The trustee may authorize the trust to borrow from the trustee as a lender provided the terms of the loan are fair to the trust unitholders. The trustee may also deposit funds awaiting distribution in an account with itself, if the interest paid to the trust at least equals amounts paid by the trustee on similar deposits, and make other short term investments with the funds distributed to the trust. The trustee may also hold funds awaiting distribution in a non-interest bearing account.

The trust will be responsible for paying all legal, accounting, tax advisory, engineering, printing costs and other administrative and out-of-pocket expenses incurred by or at the direction of the trustee or the Delaware trustee, including tax return and Schedule K-1 preparation and mailing costs, independent auditor fees and registrar and transfer agent fees. The trust will also be responsible for any payment obligations under the hedging arrangements and expenses incurred as a result of being a publicly traded entity, including costs associated with annual and quarterly reports to unitholders. These trust administrative expenses are anticipated to aggregate approximately $1.3 million per year, although such costs could be greater or less depending on future events that cannot be predicted. Included in the annual estimate is an annual administrative fee of $150,000 for the trustee, which may be adjusted beginning on April 1, 2017 as provided in the trust agreement, an annual administrative fee of $2,400 for the Delaware trustee, an annual fee of $300,000 payable to SandRidge pursuant to the terms of the administrative services agreement and an annual fee of $15,000 payable to the collateral agent under the security instruments in respect of the lien securing the trust's obligations under its direct hedge contracts. The trustee will also receive a one-time acceptance fee of $10,000. These costs will be deducted by the trust before distributions are made to trust unitholders. The trustee intends to withhold $1.0 million from the first distribution to unitholders to establish a cash reserve available to the trustee to pay trust administrative expenses.

Formation Transactions

At or prior to the closing of the offering, SandRidge will cause to be conveyed to the trust a 80% royalty interest in the Producing Wells and a 70% royalty interest in the Development Wells.

The 80% royalty interest in the Producing Wells will consist of a term royalty interest entitling the trust to receive 40% of the proceeds from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Producing Wells (after deducting post-production costs and any applicable taxes) for a period of 20 years commencing on April 1, 2011 (the "Term PDP Royalty") and a perpetual royalty interest entitling the trust to receive 40% of the proceeds from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Producing Wells (after deducting post-production costs and any applicable taxes) (the "Perpetual PDP Royalty").

The 70% royalty interest in the Development Wells will consist of a term royalty interest entitling the trust to receive 35% of the proceeds from the sale of the production of oil, natural gas and natural gas liquids attributable to SandRidge's net revenue interest in the Development Wells (after deducting post-production costs and any applicable taxes) for a period of 20 years commencing on April 1, 2011 (the "Term Development Royalty") and a perpetual royalty interest entitling the trust to receive 35% of the proceeds from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Development Wells (after deducting post-production costs and any applicable taxes) (the "Perpetual Development Royalty").

The Term PDP Royalty and the Term Development Royalty are collectively referred to as the "Term Royalties," while the Perpetual PDP Royalty and the Perpetual Development Royalty are collectively referred to as the "Perpetual Royalties." The Perpetual Royalties will be conveyed directly from SandRidge E&P to the trust. The Term Royalties will be conveyed from SandRidge E&P to another wholly owned subsidiary of SandRidge ("Term Royalty Subsidiary") in exchange for a demand note in a principal amount expected to be a significant portion of the net proceeds of the offering, and then assigned from that subsidiary to the trust. In exchange for the Perpetual Royalties, the trust will issue to SandRidge E&P, 9,375,000 common units and 13,125,000 subordinated units. In exchange for the Term Royalties, the trust will pay a significant portion of the net proceeds of this offering to the Term Royalty Subsidiary, and the Term Royalty Subsidiary will use such proceeds to repay the demand note to SandRidge E&P. Any proceeds not paid to the Term Royalty Subsidiary will be paid to SandRidge E&P, as additional consideration for the conveyance of the Perpetual Royalties. See "Use of Proceeds."

4,500,000 common units will be issued and retained by the trust at the initial closing, to be used to satisfy (if necessary) the over-allotment option granted to the underwriters. If the over-allotment option is exercised, the trust will sell to the underwriters such number of the retained units as is necessary to satisfy the over-allotment option, and will then deliver the net proceeds of such sale, together with any remaining unsold units, to one or more SandRidge subsidiaries as partial consideration for the conveyance of the Perpetual Royalties. If the over-allotment option is not exercised by the underwriters, the retained units will be delivered to SandRidge subsidiaries, as partial consideration for the conveyance of the Perpetual Royalties, promptly following the 30th day after the initial closing.

The trust will sell the 30,000,000 common units offered hereby to the public, representing a 57% interest in the trust.

SandRidge and the trust will enter into several agreements in connection with the conveyance of the royalty interests, including: (1) a development agreement, which sets forth SandRidge's drilling obligation to the trust with respect to the Development Wells, (2) a derivatives agreement, pursuant to which SandRidge will provide the trust with the effect of certain hedge contracts entered into between SandRidge and third parties, (3) an administrative services agreement, which outlines SandRidge's duty to provide administrative services to the trust, (4) the Drilling Support Lien and (5) a registration rights agreement, which is described under "Trust Units Eligible For Resale Registration Rights Agreement." These agreements are described in more detail below.

Termination Date; Liquidation

The trust will dissolve and begin to liquidate on the Termination Date, which is March 31, 2031, and will soon thereafter wind up its affairs and terminate. At the Termination Date, the Term Royalties will automatically revert to SandRidge, while the Perpetual Royalties will be sold and the proceeds will be distributed to the unitholders at the Termination Date or soon thereafter, but only after the trust has paid, or made reasonable provision for payment of, all liabilities of the trust. See "Description of the Royalty Interests Sale of the Perpetual Royalties." Any additional cash held in reserve by the trustee will also be distributed to unitholders.

Development Agreement and Drilling Support Lien

In connection with the closing of this offering, the trust will enter into a development agreement with SandRidge and SandRidge E&P that will obligate SandRidge to drill, or cause to be drilled, all of the

Development Wells on or before March 31, 2015. In the event of delays, SandRidge will have until March 31, 2016 to fulfill its drilling obligation. SandRidge may rely on third-party operators to fulfill a portion of its drilling obligation. In order to secure the estimated amount of the drilling costs for the trust's interests in the Development Wells, SandRidge E&P will grant to the trust the Drilling Support Lien, covering SandRidge E&P's interest in the AMI (except the Producing Wells and any other wells that are already producing and not subject to the royalty interests). The amount obtained by the trust pursuant to the Drilling Support Lien may not exceed approximately $295 million. As SandRidge fulfills its drilling obligation over time, the total dollar amount that may be recovered will be proportionately reduced and the completed Development Wells will be released from the lien.

Under the development agreement, SandRidge will be credited for drilling one full Development Well if the well is drilled and completed in the Grayburg/San Andres formation and SandRidge's net revenue interest in the well is equal to 69.3%. For a well in which SandRidge has a net revenue interest greater than or less than 69.3%, SandRidge will receive credit for such well in the proportion that its net revenue interest in the well bears to 69.3%. For example, if SandRidge drilled a well in which it has a 86.6% net revenue interest, such well would count for purposes of the development agreement as 1.25 Development Wells (i.e., 86.6% / 69.3%).

Horizontal Wells. Although SandRidge expects to satisfy its drilling obligation by drilling vertical wells, it may drill horizontal wells in the future, once certain criteria are achieved. Under the development agreement, SandRidge will be able to drill horizontal wells to satisfy its drilling obligation to the trust after five horizontal wells have been, subsequent to this offering, drilled and completed in the Grayburg/San Andres formation in the greater Fuhrman-Mascho field area (whether by SandRidge or any other operators). The initial five horizontal wells are intended to demonstrate the viability of drilling horizontal wells in the AMI, an area in which horizontal drilling and completion techniques have not previously been utilized. None of any such initial five horizontal wells that are drilled by SandRidge would count as Development Wells for purposes of the development agreement. If such initial five horizontal wells have been drilled and completed, SandRidge may, at its option, drill, or cause to be drilled, horizontal wells that will count toward the satisfaction of its drilling obligation to the trust. SandRidge is not required to drill any horizontal wells for the trust. If SandRidge chooses to drill horizontal wells to fulfill its drilling obligation, it will receive credit under the development agreement for horizontal Development Wells based on the proportion that SandRidge's net revenue interest in a horizontal Development Well bears to 69.3% and based on a ratio of capital costs for such horizontal wells compared to historical drilling costs. For the first ten horizontal Development Wells that SandRidge drills and completes in the Grayburg/San Andres formation, this ratio will be calculated using the proportion that the capital cost required to drill and complete such well bears to the average drilling and completion cost per well of the most recent 20 vertical Development Wells. For example, if SandRidge drilled, or caused to be drilled, a horizontal Development Well in which it had a 69.3% net revenue interest, and such well cost $2.0 million to drill and complete relative to an average drilling and completion cost of $.5 million per well for the most recent 20 vertical Development Wells completed at the time the first horizontal Development Well was completed, then such horizontal well would count for purposes of the development agreement as four Development Wells (i.e., (69.3% / 69.3%) × ($2.0 million / $.5 million)).

After the first ten horizontal Development Wells that SandRidge drills, or causes to be drilled, are completed, this ratio will be fixed for all additional horizontal wells it drills and completes in the Grayburg/San Andres formation based on the costs of the first ten horizontal Development Wells. This fixed ratio (the "CapEx Ratio") will be calculated by dividing (1) the average capital cost spent per well to drill and complete the first ten horizontal Development Wells by (2) the average capital cost spent per well to drill and complete the 20 vertical Development Wells most recently completed at the time the first horizontal Development Well was completed. Credit would be given to SandRidge for each horizontal Development Well completed based on the CapEx Ratio and the proportion that SandRidge's net revenue interest in such well bears to 69.3%. For example, if SandRidge drilled, or caused to be drilled, a horizontal

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Development Well in which it had a 69.3% net revenue interest and the CapEx Ratio was equal to four, such well would count for purposes of the development agreement as four Development Wells (i.e., 4.0 × (69.3% / 69.3%)).

Additional Provisions. In drilling and completing the Development Wells, SandRidge is required to adhere to a reasonably prudent operator standard, which requires that it act with respect to the Underlying Properties as it would act with respect to its own properties, disregarding the existence of the royalty interests as burdens affecting such properties. For example, SandRidge is required to complete and equip each Development Well that reasonably appears to SandRidge to be capable of producing oil, natural gas and natural gas liquids in quantities sufficient to pay completion, equipping and operating costs.

The proved undeveloped reserves reflected in the reserve report assume that SandRidge will drill and complete the 888 Development Wells with the same completion technique, and bearing the same capital and other costs, as the 509 Producing Wells, all of which were drilled and completed as vertical wells. The trust will not bear any of the costs of drilling and completing the Development Wells that SandRidge drills or causes to be drilled.

SandRidge may drill up to five horizontal wells to test the results of horizontal drilling in the AMI, but is not required to do so. The trust would not own any interests in such test horizontal wells and such wells would not count toward SandRidge's drilling obligation. Otherwise, SandRidge will covenant and agree not to drill and complete, and will not permit any other person within its control to drill and complete, any well in the AMI other than a Development Well until such time as SandRidge has met its commitment to drill the Development Wells. Once SandRidge has completed its drilling obligation, the trustee will be required to release the Drilling Support Lien in full. Upon the trustee's release of the Drilling Support Lien, SandRidge will further agree not to drill and complete, and will not permit any other person within its control to drill and complete, any well that will have a perforation that will be within 170 feet of any perforation of any Development Well or Producing Well.

Given that SandRidge's actual net revenue interest in each Development Well may be greater than or less than 69.3%, and that SandRidge may drill and complete horizontal wells in order to fulfill its drilling obligation, SandRidge may be required to drill more or less than 888 gross wells in order to fulfill its drilling obligation.

Hedging Arrangements

Hedging arrangements covering a portion of expected production will be implemented by the trust in two ways. First, SandRidge will enter into a derivatives agreement with the trust to provide the trust with the effect of specified hedge contracts entered into between SandRidge and third parties. Under the derivatives agreement, SandRidge will pay the trust amounts it receives from its hedge counterparties, and the trust will pay SandRidge any amounts that SandRidge is required to pay such counterparties. Second, the trust will enter into hedge contracts directly with unaffiliated hedge counterparties. As a party to these contracts, the trust will receive payments directly from its counterparties, and be required to pay any amounts owed directly to its counterparties. Under the derivatives agreement, as Development Wells are drilled, SandRidge will have the right to assign or novate to the trust any of the SandRidge-provided hedges, or to replace them with hedges executed by the trust directly with counterparties, as long as the hedging effects of the assigned or replacement hedges are economically equivalent to the hedging effects of the SandRidge-provided hedges, the counterparties to the assigned or replacement hedges have a corporate credit rating equal to or better than A/A2 as rated by Standard and Poor's or Moody's and the counterparties to the existing hedges approve.

The trust's counterparty under the derivatives agreement is SandRidge, whose hedge counterparties will be institutions with corporate credit ratings equal to or better than A/A2, including Morgan Stanley Capital Group Inc., J. Aron & Company, an affiliate of Goldman, Sachs & Co., and Barclays Bank PLC. The counterparties to the trust's direct hedging contracts will also be institutions with corporate credit

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ratings of at least A/A2, including Morgan Stanley Capital Group Inc., J. Aron & Company, an affiliate of Goldman, Sachs & Co., and Barclays Bank PLC. In the event that one or more counterparties to the trust's hedging arrangements default on their obligations to make payments under such arrangements, the cash distributions to the trust unitholders could be materially reduced as the hedge payments are intended to provide additional cash to the trust during periods of lower oil and natural gas prices. SandRidge will not be required to pay the trust to the extent of payment defaults by SandRidge's hedge contract counterparties. SandRidge will also have authority, in its role as hedge manager to the trust, to terminate, restructure or otherwise modify a portion of the trust's hedge contracts to the extent that SandRidge reasonably determines that the volumes hedged under such portion of the contracts exceed, or are expected to exceed, estimated production attributable to the trust's royalty interests over the periods hedged. Except in the limited circumstances involving the restructuring of an existing hedge, the trust will not have the ability to enter into additional hedges on its own and, accordingly, after the expiration of the hedging arrangements in March 31, 2015, there will be no hedges going forward. For more information on SandRidge's role as hedge manager for the trust, please see " Administrative Services Agreement."

The trust's obligations to the counterparties under its direct hedge contracts will be secured by a first priority lien on the trust's existing and future royalty interest in the Underlying Properties. In addition, the trust's direct hedge contracts will contain a prohibition on the trust granting additional liens on its existing and future royalty interest in the Underlying Properties, other than customary permitted liens and liens in favor of the trustee.

Under the combined hedging arrangements, approximately 73% of the expected production and 79% of the expected revenues upon which the target distributions are based from August 1, 2011 through March 31, 2015 will be hedged. All of the hedge contracts relate to oil production. Expressed in terms of oil production alone, approximately 84% of the estimated oil production from August 1, 2011 through March 31, 2015, will be hedged. The remaining estimated production of oil during that time, all production of natural gas and natural gas liquids during that time, and all production after such time will not be hedged.

The following table illustrates the type of contract, notional amount and weighted average fixed price or collar range for the oil hedge contracts that the trust will enter into directly or that SandRidge will pass through to the trust under the derivatives agreement.

Period and Type of Contract	Notional Amount (Bbls/d)	Weighted Average Fixed Price
August 1, 2011 to December 31, 2011	2,714	$ 99.80
January 1, 2012 to December 31, 2012	3,151	102.20
January 1, 2013 to December 31, 2013	3,530	102.84
January 1, 2014 to December 31, 2014	3,867	101.75
January 1, 2015 to March 31, 2015	3,373	100.90

Administrative Services Agreement

In connection with the closing of this offering, the trust will enter into an administrative services agreement with SandRidge pursuant to which SandRidge will provide the trust with certain accounting, tax preparation, bookkeeping and informational services related to the royalty interests and the registration rights agreement.

Additionally, the administrative services agreement will designate SandRidge as the trust's hedge manager, pursuant to which SandRidge will have authority to administer the hedge contracts underlying the derivatives agreement, and, on behalf of the trust, to administer the trust's direct hedge contracts. As hedge manager, SandRidge will also have authority, in its discretion, to terminate, restructure or otherwise modify any or all of such hedge contracts to the extent that SandRidge reasonably determines that the volumes hedged under such contracts exceed, or are expected to exceed, estimated production attributable to the trust's royalty interests over the periods hedged. SandRidge will be required to use commercially reasonable efforts to effect such modifications to the hedge contracts in a manner that is cash neutral to the trust, for example, by resetting hedge prices and/or allocating a portion of hedged volumes over an extended period. However, in fulfilling its role as hedge manager, SandRidge will not act as a fiduciary for the trust, will have no affirmative duty to modify any of the trust's hedges, and will have no liability to the trust in connection with SandRidge's failure to modify, or any affirmative modification of, any of the trust's hedges. Moreover, SandRidge will be indemnified by the trust for any actions it takes in this regard.

In return for the services provided by SandRidge to the trust under the administrative services agreement, the trust will pay SandRidge, on a quarterly basis, a total annual fee of $300,000. SandRidge will also be entitled to receive reimbursement for its actual out-of-pocket fees, costs and expenses incurred in connection with the provision of any of the services under the agreement.

The administrative services agreement will terminate upon the earliest to occur of: (a) the date the trust shall have dissolved and commenced winding up in accordance with the trust agreement, (b) the date that all of the royalty interests have been terminated or are no longer held by the trust, (c) with respect to services to be provided with respect to any Underlying Properties being transferred by SandRidge, the date that either SandRidge or the trustee may designate by delivering 90-days prior written notice, provided that SandRidge's drilling obligation has been completed and the transferee of such Underlying Properties assumes responsibility to perform the services in place of SandRidge and (d) a date mutually agreed by SandRidge and the trustee.

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TARGET DISTRIBUTIONS AND SUBORDINATION AND INCENTIVE THRESHOLDS

SandRidge will convey to the trust royalty interests in specified oil, natural gas and natural gas liquids properties in the AMI. The PDP Royalty Interest will entitle the trust to receive 80% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Producing Wells for a period of 20 years commencing on April 1, 2011. The Development Royalty Interest will entitle the trust to receive 70% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of future production of oil, natural gas and natural gas liquids attributable to SandRidge's net revenue interest in the Development Wells for a period of 20 years commencing on April 1, 2011.

The amount of trust revenues and cash distributions to trust unitholders will depend on:

- the timing of initial production from the Development Wells;
- oil, natural gas and natural gas liquids prices received;
- the volume of oil, natural gas and natural gas liquids produced and sold;
- amounts realized and paid under hedging arrangements;
- post-production costs and any applicable taxes; and
- the trust's general and administrative expenses.

SandRidge has calculated quarterly target levels of cash distributions for the life of the trust. Such target distribution levels are set forth on Annex B to this prospectus. The target distributions were prepared by SandRidge on a cash basis based on assumptions of production volumes, pricing and other assumptions that are described below in " Significant Assumptions Used to Calculate the Target Distributions." The production forecasts are estimates prepared by Netherland Sewell and have been used to calculate target distributions. Actual cash distributions may vary from those presented. SandRidge will pay to the trust each quarter an amount equal to the trust's royalty interest in the proceeds of production from the Underlying Properties received during the calendar quarter most recently ended (after deducting post-production costs and any applicable taxes). The trust, in turn, will make quarterly cash distributions of substantially all of its quarterly cash receipts, after deduction of fees and expenses for the administration of the trust, to holders of trust units.

The first distribution, which will cover the second and third quarters of 2011, is expected to be made on or about November 30, 2011 to record unitholders as of November 15, 2011. The trustee intends to withhold $1.0 million from the first distribution to establish a cash reserve available to pay trust administrative expenses. If the trustee uses such cash reserve to pay for trust administrative expenses, the reserve must be replenished before any further quarterly distributions are made to trust unitholders. Due to the timing of the payment of production proceeds to the trust, the trust expects that the first distribution will include sales for oil, natural gas and natural gas liquids for five months. Thereafter, quarterly distributions will generally include royalties on sales of oil, natural gas and natural gas liquids for three months, including the first two months of the quarter just ended as well as the last month of the immediately preceding quarter. Because payments to the trust will be generated by depleting assets and production from the Underlying Properties will diminish over time, a portion of each distribution will represent a return of your original investment.

In order to provide support for cash distributions on the common units, SandRidge has agreed to subordinate 13,125,000 of the trust units it will retain following this offering, which will constitute 25% of the total trust units outstanding. The subordinated units will be entitled to receive pro rata distributions from the trust 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

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fund such a distribution on all trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. Each applicable quarterly subordination threshold is 20% below the target distribution level for the corresponding quarter, as reflected on Annex B. In exchange for agreeing to subordinate these trust units, and in order to provide additional financial incentive to SandRidge to perform its drilling obligation and operations on the Underlying Properties in an efficient and cost-effective manner, SandRidge will be entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the trust units in any quarter during the subordination period exceeds the target distribution for such quarter by more than 20%. SandRidge's right to receive incentive distributions will terminate upon the expiration of the subordination period.

The subordinated units will automatically convert into common units on a one-for-one basis and SandRidge's right to receive incentive distributions will terminate at the end of the fourth full calendar quarter following SandRidge's satisfaction of its drilling obligation to the trust. SandRidge currently expects that it will complete its drilling obligation on or before March 31, 2015 and that, accordingly, the subordinated units would convert into common units on or before March 31, 2016. In the event of delays, SandRidge will have until March 31, 2016 under the development agreement to drill all the Development Wells, in which event the subordinated units would convert into common units on or before March 31, 2017.

SandRidge's management has prepared the prospective financial information set forth below to present the target distributions to the holders of the trust units based on the estimates and assumptions described below. The accompanying prospective financial information was not prepared with a view toward complying with the guidelines of the SEC or the guidelines established by the American Institute of Certified Public Accountants with respect to preparation and presentation of prospective financial information. More specifically, such information omits items that are not relevant to the trust, such as changes in financial position, an earnings per unit measure and certain non-cash expenses for depreciation, depletion and amortization used to arrive at a GAAP net income measure. SandRidge's management believes the prospective financial information was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management's knowledge and belief, the expected course of action and the expected future financial performance of the royalty interests. However, this information is based on estimates and judgments, and readers of this prospectus are cautioned not to place undue reliance on the prospective financial information.

The prospective financial information included in this prospectus has been prepared by, and is the responsibility of, SandRidge's management. Neither PricewaterhouseCoopers LLP, the trust's and SandRidge's independent registered public accountant, nor Hansen Barnett & Maxwell, P.C., Arena Resources, Inc.'s independent registered public accountant, has examined, compiled or performed any procedures with respect to the accompanying prospective financial information and, accordingly, neither PricewaterhouseCoopers LLP nor Hansen Barnett & Maxwell, P.C. expresses an opinion or any other form of assurance with respect thereto. The reports of PricewaterhouseCoopers LLP included in this prospectus relate to the Statement of Assets and Trust Corpus of the trust and the historical Statements of Revenues and Direct Operating Expenses of the Arena Properties, and the report of Hansen Barnett & Maxwell, P.C. included in this prospectus relates to the historical consolidated financial statements of Arena Resources, Inc. The foregoing reports do not extend to the prospective financial information and should not be read to do so.

The following table sets forth the target distributions and subordination and incentive thresholds for each calendar quarter through the first quarter of 2017. The effective date of the conveyance of the royalty interests is April 1, 2011, which means that the trust will receive credit for the proceeds of production

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attributable to the royalty interests from that date even though the trust properties will not be conveyed to the trust until the closing of this offering.

Period	Subordination Threshold(1)	Target Distribution	Incentive Threshold(1)
		(per unit)	
2011:			
Second and Third Quarters(2)	$ .53	$ .66	$ .79
Fourth Quarter	.39	.49	.59
2012:			
First Quarter	.42	.53	.63
Second Quarter	.44	.55	.66
Third Quarter	.47	.58	.70
Fourth Quarter	.49	.62	.74
2013:			
First Quarter	.51	.64	.77
Second Quarter	.53	.66	.80
Third Quarter	.56	.70	.84
Fourth Quarter	.58	.73	.87
2014:			
First Quarter	.61	.76	.91
Second Quarter	.63	.79	.95
Third Quarter	.65	.82	.98
Fourth Quarter	.66	.82	.98
2015:			
First Quarter	.64	.80	.96
Second Quarter	.61	.77	.92
Third Quarter	.56	.70	.85
Fourth Quarter	.54	.68	.81
2016:			
First Quarter	.53	.67	.80
Second Quarter	.52	.65	.78
Third Quarter	.51	.64	.77
Fourth Quarter	.50	.63	.75
2017:			
First Quarter	.49	.61	.74

(1) The subordination and incentive thresholds terminate after the fourth full calendar quarter following SandRidge's completion of its drilling obligation.

(2) Includes proceeds attributable to the first five months of production from April 1, 2011 to August 31, 2011, and gives effect to $1.0 million of reserves for general and administrative expenses withheld by the trustee and additional administrative costs relating to the formation of the trust.

SandRidge has prepared the operational and financial information set forth above and below in order to present the target distributions attributable to the oil, natural gas and natural gas liquids sales volumes reflected in the reserve report attached hereto as Annex A. The target distributions, in the view of SandRidge's management, were prepared on a reasonable basis based on the assumptions outlined in " Significant Assumptions Used to Calculate the Target Distributions."

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The operational and financial targets outlined below should not be relied upon as being necessarily indicative of future results. Neither SandRidge nor the trust undertakes any obligation to update the financial forecast to reflect events or circumstances after the date of this prospectus and readers of this prospectus are cautioned not to place undue reliance on this financial information.

The projections and assumptions on which they are based are subject to significant uncertainties, many of which are beyond the control of SandRidge and the trust. **Actual cash distributions to trust unitholders, therefore, could vary significantly based upon events or conditions occurring that are different from the events or conditions assumed to occur for purposes of these operational and financial targets.**

Cash distributions to trust unitholders will be particularly sensitive to fluctuations in oil, natural gas and natural gas liquids prices and production volumes. See " Sensitivity of Target Distributions to Oil, Natural Gas and Natural Gas Liquids Prices and Volumes," which shows estimated effects to cash distributions through June 30, 2012 from changes in assumed realized oil, natural gas and natural gas liquids prices as well as changes in estimated production volumes. As a result of typical production declines for oil, natural gas and natural gas liquids properties, production estimates generally decrease from year to year. However, the production estimates included in the table below reflect that these declines are expected to be offset by additional production from Development Wells as they are completed and begin to produce. The timing of the completion of, and the amount of production attributable to, the Development Wells are substantially dependent on SandRidge executing its drilling plans with respect to the drilling and completion of the Development Wells in a manner substantially similar to those underlying the assumptions used in establishing these target distributions. In addition, the completion of SandRidge's drilling obligation will depend, in part, on the completion of drilling for certain Development Wells by third parties, over whom SandRidge has no control, in a manner consistent with the assumptions used in establishing these target distributions. Please see "Risk Factors" for risks relating to the timing of drilling and amount of production attributable to the Development Wells. **As a result of these factors, the target distributions shown in the tables below are not necessarily indicative of distributions for future years.**

Because payments to the trust will be generated by depleting assets and production from the Underlying Properties will diminish over time, a portion of each distribution will represent a return of your original investment. See "Risk Factors The oil, natural gas and natural gas liquids reserves estimated to be attributable to the Underlying Properties of the trust are depleting assets and production from those reserves will diminish over time. Furthermore, the trust is precluded from acquiring other oil and gas properties or royalty interests to replace the depleting assets and production."

The table below presents the calculation of the target distributions for each quarter through and including the quarter ending June 30, 2012. On a pro forma basis, the trust's distributable income was

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$60.7 million ($1.16 per unit) for the year ended December 31, 2010, and $19.7 million ($0.37 per unit) for the three months ended March 31, 2011. See "Unaudited Pro Forma Financial Information."

	September 30, 2011[(1)]	December 31, 2011	March 31, 2012	June 30, 2012
	(In thousands, except volumetric and per unit data)			
Estimated production from trust properties				
Oil sales volumes (MBbl)	384	278	294	306
Natural gas sales volumes (MMcf)	107	74	78	80
Natural gas liquids volumes (MBbl)	40	29	30	32
Total sales volumes (MBoe)	441	319	337	351
% Proved developed producing (PDP) sales volumes	88%	57%	48%	42%
% Proved undeveloped (PUD) sales volumes	12%	43%	52%	58%
% Oil volumes	87%	87%	87%	87%
% Natural gas volumes	4%	4%	4%	4%
% Natural gas liquids volumes	9%	9%	9%	9%
Commodity price and derivative contract positions				
NYMEX futures price[(2)]				
Oil ($/Bbl)	$ 99.33	$ 98.03	$ 99.48	$ 100.70
Natural gas ($/MMBtu)	$ 4.40	$ 4.57	$ 4.88	$ 4.81
Natural gas liquids ($/Bbl)	$ 49.61	$ 49.01	$ 49.74	$ 50.35
Assumed realized weighted unhedged price[(3)]				
Oil ($/Bbl)	$ 95.97	$ 93.76	$ 95.21	$ 96.43
Natural gas ($/Mcf)	3.17	3.29	3.51	3.46
Natural gas liquids ($/Bbl)	47.97	47.40	48.10	48.69
Assumed realized weighted hedged price				
Oil ($/Bbl)	96.53	95.34	97.04	97.85
Natural gas ($/Mcf)	3.17	3.29	3.51	3.46
Percent of oil volumes hedged	98%[(4)]	89%	93%	95%
Oil hedged price ($/Bbl)	99.80	99.80	101.46	102.20
Percent of natural gas volumes hedged	0%	0%	0%	0%
Natural gas hedged price ($/MMBtu)				
Estimated cash available for distribution				
Oil sales revenues	$ 36,814	$ 26,067	$ 27,982	$ 29,552
Natural gas sales revenues	338	243	273	279
Natural gas liquids sales revenue	1,916	1,374	1,463	1,536
Realized gains (losses) from derivative contracts	215	441	539	436
Operating revenues and realized gains (losses) from derivative contracts	$ 39,283	$ 28,125	$ 30,257	$ 31,803
Production taxes	(1,862)	(1,320)	(1,417)	(1,496)
Ad valorem taxes	(977)	(692)	(743)	(784)
Franchise taxes	(137)	(98)	(106)	(111)
Trust administrative expenses	(1,750)[(5)]	(325)	(325)	(325)
Total trust expenses	(4,727)	(2,436)	(2,591)	(2,716)
Cash available for distribution	$ 34,556	$ 25,689	$ 27,666	$ 29,087
Trust units outstanding	52,500	52,500	52,500	52,500
Target distribution per trust unit	$ .66	$ .49	$ .53	$ .55
Subordination threshold per trust unit	$ ..53	$ ..39	$ ..42	$ ..44

Incentive threshold per trust unit	$	..79	$	..59	$	..63	$	..66

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	September 30, 2011(1)	December 31, 2011	March 31, 2012	June 30, 2012
	(In thousands, except volumetric and per unit data)			
If actual cash exceeds target by 20%	$ 41,468	$ 30,827	$ 33,199	$ 34,904
Cash necessary to meet incentive threshold	41,468	30,827	33,199	34,904
Excess cash available for incentive distributions				
Distributions to unitholders(6)				
Incentive distributions to SandRidge				
If actual cash available exceeds target by 40%	48,379	35,965	38,732	40,721
Cash necessary to meet incentive threshold	41,468	30,827	33,199	34,904
Excess cash available for incentive distributions	6,911	5,138	5,533	5,817
Distributions to unitholders(6)	3,456	2,569	2,767	2,909
Incentive distributions to SandRidge	3,456	2,569	2,767	2,909
If actual cash available falls short of target by 20%	27,645	20,551	22,133	23,269
Cash available for distribution to common units	20,734	15,413	16,600	17,452
Cash necessary to meet common unit subordination threshold	20,734	15,413	16,600	17,452
Cash short of subordination threshold				
Reduction in distribution to subordinated units to support subordination threshold				
Cash distributions to common unitholders	20,734	15,413	16,660	17,452
Cash distributions to subordinated units	6,911	5,138	5,533	5,817
If actual cash available falls short of target by 40%	20,734	15,413	16,660	17,452
Cash available for distribution to common units	15,550	11,560	12,450	13,089
Cash necessary to meet common unit subordination threshold	20,734	15,413	16,600	17,452
Cash short of subordination threshold	(5,183)	(3,853)	(4,150)	(4,363)
Reduction in distribution to subordinated units to support subordination threshold	5,183	3,853	4,150	4,363
Cash distributions to common unitholders	$ 20,734	$ 15,413	$ 16,600	$ 17,452
Cash distributions to subordinated units				

(1) Includes proceeds attributable to the first five months of production from April 1, 2011 to August 31, 2011.

(2) Average NYMEX futures prices, as reported July 15, 2011. For a description of the effect of lower NYMEX prices on target distributions, please read " Sensitivity of Target Distributions to Changes in Oil, Natural Gas and Natural Gas Liquids Prices and Volumes."

(3)

Sales price net of forecasted quality, Btu content, transportation costs, and marketing costs. For information about the estimates and assumptions made in preparing the table above, see " Significant Assumptions Used to Calculate the Target Distributions."

(4)
Hedging percentage excludes production from April 1, 2011 to July 31, 2011.

(5)
Includes trustee cash reserve of $1.0 million and additional administrative costs relating to the formation of the trust.

(6)
Includes distributions to SandRidge on a pro rata basis.

Significant Assumptions Used to Calculate the Target Distributions

In preparing the target distributions and subordination and incentive threshold tables above and sensitivity tables below, the revenues and expenses of the trust were calculated based on the terms of the conveyances creating the trust's royalty interests using the following assumptions and those set forth above under "Target Distributions and Subordination and Incentive Thresholds." These calculations are described under "Description of the Royalty Interests."

Production Estimates. Production estimates for each of the quarters during the life of the trust are based on the reserve report, adjusted for actual volumes realized in April, May and June 2011. The

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estimates of reserves and production relating to the Underlying Properties and the royalty interests included in the reserve report have been made in accordance with the SEC's rules for reserve reporting. Production attributable to the royalty interests from the Underlying Properties for the 12-months ending March 31, 2012 is estimated to be 1,223 MBoe. However, due to the timing of the payment of production proceeds to the trust, the production attributable to the distributions for the 12-months ending March 31, 2012 will be for the 11-months ending February 28, 2012, estimated to be 1,107 MBoe. The estimated production in the forecast period gives effect to the drilling and completion by SandRidge of approximately 888 Development Wells per year during the four-year drilling period, and the completion by SandRidge of its drilling obligation to the trust of 888 Development Wells on or before March 31, 2015. As a reasonably prudent operator, SandRidge is obligated to drill and complete the Development Wells consistent with the drilling and completion techniques used in the Producing Wells to enhance oil, natural gas and natural gas liquids recovery in a cost effective manner. See " Oil Prices" and " Natural Gas Prices" below for a description of changes in production due to price variations. Differing levels of production will result in different levels of distributions and cash returns.

If oil, natural gas and natural gas liquids prices decline, the operators of producing oil, natural gas and natural gas liquids properties may elect to reduce or completely suspend production. SandRidge is required under the applicable conveyance to act as a reasonably prudent operator with respect to the Underlying Properties under the same or similar circumstances as it would act if it were acting with respect to its own properties, disregarding the existence of the royalty interests as burdens affecting such properties. No adjustments have been made to estimated production in the tables above to reflect potential reductions or suspensions of production by SandRidge or third party operators.

Oil Prices. The assumed oil prices utilized for purposes of preparing the target distributions are based on settled NYMEX pricing for April through June 2011, monthly NYMEX forward pricing for the remainder of the period ending March 31, 2014 and assumed price increases after March 31, 2014 of 2.5% annually, capped at $120.00 per Bbl. Using these assumptions, the price per Bbl would reach the $120.00 per Bbl cap in 2023. The table below sets forth NYMEX forward pricing as of July 15, 2011 for the period ending March 31, 2014.

Estimated Market Prices for Oil ($/Bbl)
Based on NYMEX Pricing as of July 15, 2011

	2011	2012	2013	2014
January		99.49	102.99	103.55
February		99.94	103.06	103.47
March		100.34	103.12	103.40
April	$ 109.96(1)	100.71	103.17	
May	101.28(1)	101.04	103.21	
June	96.25(1)	101.36	103.25	
July	93.40	101.66	103.21	
August	97.24	101.88	103.23	
September	97.60	102.10	103.26	
October	97.99	102.33	103.35	
November	98.46	102.60	103.48	
December	98.99	102.90	103.64	

(1) Based on settled NYMEX pricing.

Natural Gas Prices. The assumed natural gas prices utilized for purposes of preparing the target distributions are based on NYMEX forward pricing for the remainder of the period ending March 31, 2014 and assumed price increases after March 31, 2014 of 2.5% annually, capped at $7.00 per MMBtu. Using

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these assumptions, the price per MMBtu would reach the $7.00 per MMBtu cap in 2022. The table below sets forth NYMEX forward pricing as of July 15, 2011 for the period ending March 31, 2014.

Estimated Market Prices for Natural Gas ($/MMBtu)
Based on NYMEX Pricing as of July 15, 2011

	2011	2012	2013	2014
January		4.91	5.40	5.69
February		4.91	5.37	5.66
March		4.86	5.29	5.57
April	$ 4.24(1)	4.77	5.06	
May	4.31(1)	4.79	5.07	
June	4.54(1)	4.82	5.10	
July	4.36	4.86	5.14	
August	4.55	4.88	5.17	
September	4.52	4.89	5.18	
October	4.54	4.93	5.22	
November	4.64	5.07	5.36	
December	4.82	5.29	5.57	

(1) Based on settled NYMEX pricing.

Natural Gas Liquids Prices. The assumed natural gas liquids prices utilized for purposes of preparing the target distributions are based on the pricing for oil set forth above the heading " Oil Prices," as well as a 51.65% negative differential from such prices in each relevant period.

Hedging. The trust will enter into hedge contracts directly with unaffiliated counterparties. Additionally, SandRidge will enter into a derivatives agreement with the trust in order to transfer to the trust the effect of the hedge contracts entered into between SandRidge and third parties. Pursuant to these arrangements, approximately 73% of the expected production and 79% of the expected revenues upon which the target distributions are based from August 1, 2011 through March 31, 2015 will be hedged. See "The Trust Hedging Arrangements."

Differentials. Proceeds to the trust will be calculated based on the actual price realized by SandRidge for oil, natural gas and natural gas liquids produced, which will differ from NYMEX prices as a result of:

- discounts based on location,
- quality of oil, natural gas and natural gas liquids produced,
- estimated fuel usage for natural gas, and
- post-production costs (generally consisting of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and natural gas liquids produced).

These charges are collectively referred to as pricing "differentials" from NYMEX pricing.

To prepare the target distributions, assumed differentials were subtracted from the NYMEX prices shown in the tables above, based on an analysis by SandRidge of historical realized prices for production from the region. The estimated realized prices for natural gas assume a 28.0% negative differential from the NYMEX futures price for natural gas which accounts for the historical volatility in differentials in the region.

The estimated realized prices for oil assume a $4.27 per barrel negative differential from the NYMEX futures price for oil based on the stability in recent periods of the differential. A flat dollar differential amount has been chosen because the realized oil differential has been stable in recent years for oil produced in the Permian Basin.

The estimated realized prices for natural gas liquids assume a 51.65% negative differential from the NYMEX futures price for oil based on two separate differentials: (1) a 50% negative differential from NYMEX prices for oil based on an analysis by SandRidge of the historical mix of hydrocarbon liquids that have been produced from its wells in the region and (2) an additional 1.75% negative differential from NYMEX prices for oil associated with fees paid for gathering and processing of the natural gas liquids, consistent with SandRidge's service contracts currently in place.

There can be no assurance that realized prices in the future will be the same as historical realized prices or the assumed realized prices used to prepare the target distributions.

Administrative Expense. Trust administrative expense per year is estimated to be approximately $1.3 million, although such costs could be greater or less depending on future events that cannot be predicted. Included in this annual estimate, among other miscellaneous items, are annual administrative fees of $150,000 for the trustee and $300,000 for SandRidge. It has been assumed that the annual fee to SandRidge will remain flat for the life of the trust, the annual fee to the trustee will escalate at 2.5% after the first quarter of 2017, and the remaining estimated costs ($850,000) will escalate at a rate of 2.5% annually starting in the third quarter of 2013. It has been assumed that the trust will also pay, out of the first cash payment received by the trust, the trustee's and Delaware trustee's legal expenses incurred in forming the trust as well as the trustee's acceptance fee in the amount of $10,000. These costs will be deducted by the trust before distributions are made to trust unitholders.

Trustee's Cash Reserve. It has been assumed that the trustee will withhold $1.0 million from the first distribution to unitholders to establish a cash reserve available for potential administrative expenses of the trust. No other cash reserves have been assumed.

Tax Treatment of Royalty Interests. For U.S. federal income tax purposes, the Term PDP Royalty will, and the Term Development Royalty should, be treated as debt instruments. Accordingly, the Term Royalties will be subject to the original issue discount, or OID, rules of the Internal Revenue Code, which require that payments made to the trust with respect to the Term Royalties will be treated first as consisting of a payment of interest to the extent of interest deemed accrued under the OID rules at the applicable federal rate and the excess, if any, will be treated as a payment of principal (which is non-taxable). For federal income tax purposes, the Perpetual PDP Royalties will be, and the Perpetual Development Royalties should be, treated as mineral royalty interests, which give rise to ordinary income subject to depletion.

Timing of Actual Cash Distributions. Quarterly cash distributions will be made on or about the 60th day following the end of each calendar quarter to unitholders of record on or about the 45th day following each calendar quarter. Due to the timing of SandRidge's receipt of cash for production, it has been assumed that cash distributions for each quarter will include production from the first two months of the quarter just ended as well as the last month of the immediately preceding quarter. The first distribution, which will cover the second and third quarters of 2011, is expected to be made on or about November 30, 2011 to record unitholders as of November 15, 2011, and will include sales for oil, natural gas and natural gas liquids for the months April through August 2011. Thereafter, quarterly distributions will generally relate to production of oil, natural gas and natural gas liquids for a three month period, including one month of the prior quarter.

Applicable Taxes. Texas levies a tax on the production of oil and natural gas in the state. For oil production, Texas currently imposes a production tax at 4.6% of the market value of the oil produced. For natural gas, Texas currently imposes a production tax of 7.5% of the market value of the gas. The trust will also be subject to the Texas franchise tax, which is imposed in each year at a maximum effective rate of .7% of the trust's gross income apportioned to Texas in the prior year.

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Incentive Distributions. To the extent that the trust has cash available for distribution in excess of the incentive thresholds during the subordination period, SandRidge will be entitled to receive 50% of such cash as incentive distributions. The incentive distributions terminate upon completion of the subordination period.

Sensitivity of Target Distributions to Changes in Oil, Natural Gas and Natural Gas Liquids Prices and Volumes

The amount of revenues of the trust and cash distributions to the trust unitholders will be directly dependent on the sales price for oil, natural gas and natural gas liquids sold, the volumes of oil, natural gas and natural gas liquids produced and, to some degree, variations in property and production taxes, if any, and post-production costs. The following tables demonstrate the effect that changes in the estimated oil, natural gas and natural gas liquids production for the forecast period ending June 30, 2012 as reflected in the reserve report and the impact that fluctuations in assumed realized oil, natural gas and natural gas liquids prices could have on cash distributions to the trust unitholders.

These tables set forth the sensitivity of annual cash distributions per trust unit for the forecast period ending June 30, 2012 based upon:

- the assumption that a total of 39,375,000 common trust units and 13,125,000 subordinated units are issued and outstanding after the closing of the offering made hereby;
- an assumed initial public offering price of $20.00 per common unit;
- various realizations of oil, natural gas and natural gas liquids production levels estimated in the reserve report;
- various assumed realized oil, natural gas and natural gas liquids prices;
- assumptions regarding applicable taxes and differentials; and
- other assumptions described above under " Significant Assumptions Used to Calculate the Target Distributions."

The tables give effect to the subordination and incentive distribution features that are contained in the terms of the trust. For a description of the way in which those features would impact trust unitholders' distributions, please see "Target Distributions and Subordination and Incentive Thresholds."

The following tables are not a projection or forecast of the actual or estimated results from an investment in the common units. The purpose of these tables is to illustrate the sensitivity of cash distributions to changes in oil, natural gas and natural gas liquids production levels and the price of oil, natural gas and natural gas liquids. There is no assurance that the assumptions described below will actually occur or that oil, natural gas and natural gas liquids production levels and the prices of oil, natural gas and natural gas liquids will not change by amounts different from those shown in the tables.

The hedging arrangements for the trust will be in effect only through March 31, 2015, and thus there is likely to be greater fluctuation in cash distributions resulting from fluctuations in realized oil, natural gas and natural gas liquids prices in periods subsequent to such time. See "Risk Factors" for a discussion of various items that could impact production levels and the price of oil, natural gas and natural gas liquids.

These distributions are sensitized to both assumed NYMEX oil, natural gas and natural gas liquids prices as well as the assumed production from the trust properties. The quarterly distributions in the tables below are based on assumptions outlined in " Significant Assumptions Used to Calculate the Target Distributions." The tables set forth below provide examples of possible distributions for the quarters ending September 30, 2011, December 31, 2011 and March 31, 2012 and June 30, 2012 based on various NYMEX pricing and production assumptions.

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For scenarios in these tables that involve lower NYMEX oil or natural gas prices and production volumes, as applicable, the quarterly distribution per unit does not fall below the subordination threshold because the subordinated units support the common distributions.

For each table, the assumed NYMEX oil price per Bbl or natural gas price per MMBtu, as applicable, used to estimate quarterly distributions is also the assumed NYMEX oil price or gas price for all previous quarters.

Estimated Distribution per Common Unit
for the Quarter Ending September 30, 2011

Estimated Distribution per Common Unit
for the Quarter Ending December 31, 2011

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Estimated Distribution per Common Unit
for the Quarter Ending March 31, 2012

Estimated Distribution per Common Unit
for the Quarter Ending June 30, 2012

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SELECTED HISTORICAL AND PRO FORMA FINANCIAL AND OPERATING DATA

Separate financial statements do not exist for the Underlying Properties due to the manner in which Arena Resources, Inc. accounted for such properties. Accordingly, presented below are selected historical financial and operating data for the Arena Properties for the year ended December 31, 2010 and the three months ended March 31, 2010 and 2011, selected pro forma financial and operating data for the portion of the Underlying Properties attributable to the royalty interests to be held by the trust for the year ended December 31, 2010 and the three months ended March 31, 2011, and selected historical financial data for Arena Resources, Inc., sometimes referred to herein as Arena, for the years ended December 31, 2006, 2007, 2008 and 2009. The Underlying Properties represent approximately 40% of the Arena Properties, on a PV-10 basis, as of December 31, 2010, and have a reserve profile that is substantially consistent with the reserve profile of the Arena Properties.

The Arena Properties and the Underlying Properties

The following table shows:

- selected historical revenue and direct operating expense data, and production and average sales price data, for the Arena Properties for the year ended December 31, 2010 and the three months ended March 31, 2010 and 2011; and

- selected pro forma revenue and direct operating expense data, and production and average sales price data, for the portion of the Underlying Properties attributable to the royalty interests to be held by the trust for the year ended December 31, 2010 and the three months ended March 31, 2011.

Due to the factors described in "Management's Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting the Comparability of the Historical Financial Results of the Arena Properties or Arena Resources, Inc. to the Future Results of the Trust," the historical revenue and direct operating expenses for the Arena Properties may not be comparable to, or indicative of, the trust's future results.

The selected historical revenue and direct operating expense data for the Arena Properties for the year ended December 31, 2010 are derived from the audited historical statements of revenue and direct operating expenses of the Arena Properties included elsewhere in this prospectus. The selected historical revenue and direct operating expense data for the Arena Properties for the three months ended March 31, 2010 and 2011 are derived from the unaudited historical statements of revenue and direct operating expenses for the Arena Properties included elsewhere in this prospectus.

The selected pro forma revenue and direct operating expense data for the portion of the Underlying Properties attributable to the royalty interests to be held by the trust for the year ended December 31, 2010 and for the three months ended March 31, 2011 are derived from the unaudited pro forma financial information included elsewhere in this prospectus. The selected pro forma revenue and direct operating expense data for the portion of the Underlying Properties attributable to the royalty interests to be held by the trust reflects the exclusion of an allocated portion of the revenues and direct operating expenses of the Arena Properties corresponding to the portion of such properties that will not comprise part of the Underlying Properties, the exclusion of lease operating expenses that would not have been borne by the trust, as well as the formation of the trust and the conveyance of the PDP Royalty Interest to the trust.

You should read the following table in conjunction with "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations," "The Underlying Properties," the historical statements of revenues and direct operating expenses for the Arena Properties, and the unaudited pro forma financial information included elsewhere in this prospectus, as well as the discussion of SandRidge's business and related Management's Discussion and Analysis of Financial Condition and Results of Operations of SandRidge set forth and incorporated by reference in this prospectus. Among

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other things, those historical and unaudited pro forma financial statements include more detailed information regarding the basis of presentation for the following information.

	ARENA PROPERTIES			PRO FORMA FOR ROYALTY INTERESTS	
	Year Ended December 31, 2010	Three Months Ended March 31, 2010	Three Months Ended March 31, 2011	Year Ended December 31, 2010	Three Months Ended March 31, 2011
	(dollars in thousands, except per unit amounts)				
Oil and natural gas revenue	$ 226,339	$ 51,798	$ 73,089	$ 65,548	$ 21,166
Direct operating expenses					
Lease operating expense	28,307	4,442	12,485		
Production taxes and other post-production expenses	11,669	2,808	3,729	3,379	1,080
Total direct operating expenses	39,976	7,250	16,214	3,379	1,080
Revenue in excess of direct operating expenses	$ 186,363	$ 44,548	$ 56,875	$ 62,169	$ 20,086
Production					
Oil (Bbls)	2,953,381	631,052	870,594	855,299	252,124
Natural gas (Mcf)	2,288,175	650,828	387,698	662,655	112,277
Total production (Boe)	3,334,744	739,523	935,210	965,742	270,837
Average sales prices					
Oil (per Bbl)	$ 72.73	$ 74.84	$ 82.55	$ 72.73	$ 82.55
Natural gas (per Mcf)	$ 5.04	$ 7.02	$ 3.15	$ 5.04	$ 3.15
Production costs (per Boe)	$ 8.49	$ 6.01	$ 13.35	$	$
Post-production costs and taxes (per Boe)	$ 3.50	$ 3.80	$ 3.99	$ 3.50	$ 3.99

Arena Resources, Inc.

The following table shows selected historical financial data of Arena for the years ended December 31, 2006, 2007, 2008 and 2009. Due to the factors described in "Management's Discussion and Analysis of Financial Condition and Results of Operations Factors Affecting the Comparability of the Historical Financial Results of the Arena Properties or Arena Resources, Inc. to the Future Results of the Trust," the trust's future results will not be comparable to the historical results of Arena.

The selected historical financial data as of December 31, 2008 and 2009 and for the years ended December 31, 2008 and 2009 are derived from the audited historical consolidated financial statements of Arena included elsewhere in this prospectus. The selected historical financial data as of December 31, 2006 and 2007 and for the years ended December 31, 2006 and 2007 are derived from audited historical consolidated financial statements of Arena not included herein.

You should read the following table in conjunction with "Use of Proceeds," "Management's Discussion and Analysis of Financial Condition and Results of Operations," and the historical consolidated financial statements of Arena included elsewhere in this prospectus. Among other things, those historical

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financial statements include more detailed information regarding the basis of presentation for the following information.

	For the Year Ended December 31,			
	2006	2007	2008	2009
	(in thousands, except per share information)			
Statement of Operations Data:				
Revenues	$ 59,760	$ 100,090	$ 208,859	$ 126,241
Net income	23,268	34,442	83,617	42,294
Basic net income per common share	0.83	1.07	2.28	1.10
Diluted net income per common share	0.77	1.02	2.20	1.09

	As of December 31,			
	2006	2007	2008	2009
	(in thousands)			
Balance Sheet Data:				
Total assets	$ 176,313	$ 350,981	$ 591,685	$ 657,071
Total long-term liabilities	41,273	73,953	89,600	115,833

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This Management's Discussion and Analysis of Financial Condition and Results of Operations contains the following information:

- *a discussion and analysis of the results from the Arena Properties for the year ended December 31, 2010 and the three months ended March 31, 2010 and 2011;*

- *a discussion and analysis of the financial condition and results of operations, liquidity and capital resources, critical accounting policies and estimates and hedging of Arena Resources, Inc. for the years ended December 31, 2008 and 2009; and*

- *a discussion of the trust's liquidity and capital resources on a pro forma basis, critical accounting policies and estimates and the effects of inflation and pricing.*

The following Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the "Selected Historical and Pro Forma Financial and Operating Data" and the accompanying financial statements and related notes included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside SandRidge's and the trust's control. Actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil, natural gas and natural gas liquids, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this prospectus, particularly in "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements." In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur.

Factors Affecting the Comparability of the Historical Financial Results of the Arena Properties or Arena Resources, Inc. to the Future Results of the Trust

Separate financial statements do not exist for the Underlying Properties due to the manner in which Arena Resources, Inc. accounted for such properties. The Underlying Properties represent approximately 40% of the Arena Properties, on a PV-10 basis, as of December 31, 2010, and have a reserve profile that is substantially consistent with the reserve profile of the Arena Properties. For these reasons, SandRidge believes that the historical results of the Arena Properties for the year ended December 31, 2010 and the three months ended March 31, 2010 and 2011 provide useful information about the trends in performance over time of the Underlying Properties, which are included within the Arena Properties. However, for the reasons described below, the results of the Arena Properties and the results of operations of Arena Resources, Inc. discussed below may not be comparable to, or indicative of, the future results of the Underlying Properties or the trust:

- The historical results of the Arena Properties and the historical results of operations of Arena Resources, Inc. reflect a substantially larger asset base than the Underlying Properties.

- For periods prior to 2010, the historical results of operations of Arena Resources, Inc. are presented and discussed on a consolidated basis and include all items of income and expense presented in a consolidated statement of operations. By contrast, the statements of revenue and direct operating expenses of the Arena Properties for the year ended December 31, 2010 and for the three months ended March 31, 2010 and 2011 and the pro forma statements of revenues and direct operating expense for the portion of the Underlying Properties attributable to the royalty interests to be contributed exclude a number of items of income and expense applicable to consolidated statements of operations, such as general and administrative expenses, interest expense, depreciation, depletion and amortization, income taxes, and hedging items.

The historical statements of revenues and direct operating expenses of the Arena Properties included in this prospectus do not give effect to the terms and conditions of the royalty interests and, as a result, do not reflect what the trust's distributable income will be in the future.

The Arena Properties

Oil and natural gas revenue. Oil and natural gas revenue attributable to the Arena Properties increased to $73.1 million in the first quarter of 2011 from $51.8 million in the same period of 2010 as a result of increases in oil volumes produced and oil prices received during the 2011 period. Oil production increased to 871 MBbls for the three months ended March 31, 2011 from 631 MBbls in the same period of 2010 due to increased oil drilling activity on the Arena Properties during the second half of 2010 and first quarter of 2011. The average price received for oil production increased to $82.55 per Bbl for the three months ended March 31, 2011 from $74.84 per Bbl in the same period of 2010. The increase in oil revenue was partially offset by decreases in natural gas production and associated prices. Natural gas production decreased to 388 MMcf for the three months ended March 31, 2011 from 651 MMcf in the same period of 2010, while the average price received for natural gas production decreased to $3.15 per Mcf for the three months ended March 31, 2011 from $7.02 per Mcf in the comparable period of 2010.

Oil and natural gas revenue attributable to the Arena Properties for the year ended December 31, 2010 was $226.3 million. The average prices received during the period for oil and natural gas were $72.73 per Bbl and $5.04 per Mcf, respectively. Oil production was 2,953 MBbls and natural gas production was 2,288 MMcf for the year ended December 31, 2010.

Lease operating expense. Lease operating expense attributable to the Arena Properties increased to $12.5 million, or $13.35 per Boe, for the three months ended March 31, 2011 from $4.4 million, or $6.01 per Boe, in the comparable period of 2010. The increase was primarily due to workover activity conducted on the properties after their acquisition by SandRidge in July 2010 as well as increased overall activity associated with the properties during the second half of 2010 and first quarter of 2011.

Lease operating expense attributable to the Arena Properties for the year ended December 31, 2010 was $28.3 million or $8.49 per Boe.

Production taxes and other post-production expenses. Production taxes and other post-production expenses attributable to the Arena Properties increased to $3.7 million, or $3.99 per Boe, for the three months ended March 31, 2011 from $2.8 million, or $3.80 per Boe, for the same period in 2010 due to increased oil and natural gas revenue during the 2011 period.

Production taxes and other post-production expenses were $11.7 million, or $3.50 per Boe, for the year ended December 31, 2010. Production taxes and other post-production expenses on a per Boe basis were higher during the three months ended March 31, 2011 than the year ended December 31, 2010 primarily as a result of higher prices received for production during the three months ended March 31, 2011. The average price received for oil production was $82.55 per Bbl during the three months ended March 31, 2011 compared to $72.73 per Bbl for the year ended December 31, 2010.

Conversion of Proved Undeveloped Reserves. During 2010, approximately 370 wells were drilled and approximately $193.8 million of drilling capital expenditures was spent to convert approximately 9 MMBoe of proved undeveloped reserves to proved developed reserves.

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Arena Resources, Inc.

Historical Results of Operations

	For the Years Ended December 31,	
	2008	2009
	(in thousands, except per unit amounts)	
Net production:		
Oil (Bbls)	2,018	2,004
Natural gas (Mcf)	1,912	2,173
Net sales:		
Oil	$ 190,051	$ 115,285
Natural gas	18,808	10,956
Average sales price:		
Oil (per Bbl)	$ 94.16	$ 57.51
Natural gas (per Mcf)	9.84	5.04
Total (per Boe)	89.37	53.34
Production costs and expenses:		
Oil and gas production costs	$ 17,833	$ 15,543
Production taxes	10,518	6,456
Realized loss (gain) on oil derivative	4,275	(14,885)
Depreciation, depletion and amortization expense	29,790	38,957
Accretion expense	309	411
General and administrative expenses	13,557	13,453
Average production cost (per Boe)	$ 7.63	$ 6.57
Average production taxes (per Boe)	4.50	2.73

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Oil and Natural Gas Sales. Arena's oil and natural gas sales revenue decreased approximately $82.6 million to $126.2 million in 2009. Oil sales decreased $74.8 million and natural gas sales decreased $7.8 million. The oil sales decrease was caused by a 39% decrease in the average realized per barrel oil price from $94.16 in 2008 to $57.51 in 2009 and a reduction in sales volume of 13.8 MBbls in 2009. These per barrel amounts are calculated by dividing revenue from oil sales by the volume of oil sold, in barrels. The natural gas sales decrease was caused by a 49% decrease in the average realized per Mcf gas price from $9.84 in 2008 to $5.04 in 2009, partially offset by an increase in the sales volume of 261,078 Mcf. These per Mcf amounts are calculated by dividing revenue from gas sales by the volume of gas sold, in Mcf. The volume increase for natural gas primarily resulted from development of existing properties in 2009.

Oil and Gas Production Costs. Aggregate oil and gas production costs decreased from $17.8 million in 2008 to $15.5 million, and decreased on a Boe basis from $7.63 in 2008 to $6.57 in 2009. These per Boe amounts are calculated by dividing the total production costs by the total volume sold, in Boe. This decrease in the aggregate and on a per Boe basis was the result of lower average costs for services and equipment.

Oil and Gas Production Taxes. Oil and gas production taxes as a percentage of oil and natural gas sales were 5.04% during 2008 and increased slightly to 5.11% in 2009.

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Realized Loss (Gain) on Oil Derivative. Realized loss (gain) on oil derivative changed from a loss of $4.3 million in 2008 to a gain of $14.9 million in 2009. This change was the result of significantly lower prices for the majority of 2009 as compared to 2008.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased by $9.3 million to $39.4 million in 2009. The increase was a result of an increase in the average depreciation, depletion and amortization rate from $12.88 per Boe during 2008 to $16.63 per Boe during 2009. These per Boe amounts were calculated by dividing total depreciation, depletion and amortization expense by total volume sold, in Boe. The increased depreciation, depletion and amortization was the result of an increase in estimated future development costs.

General and Administrative Expenses. General and administrative expenses remained relatively steady, decreasing by $0.1 million to $13.5 million during 2009. This decrease was primarily related to a decrease in compensation expense related to Arena's stock option plan, partially offset by increases in other areas, such as insurance and taxes and fees.

Interest Income. Interest income decreased $0.5 million to $0.8 million in 2009. The decrease was primarily due to lower interest rates between periods.

Interest Expense. Interest expense decreased $1.1 million to $0 in 2009. The decrease was due to not having any amounts outstanding on Arena's credit facility during 2009.

Income Tax Expense. Arena's effective tax rate was 37% during 2008 and 37% during 2009.

Net Income. Net income decreased from $83.6 million for 2008 to $42.3 million for 2009. The primary reason for this decrease was the lower average crude oil and natural gas prices received between periods.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Oil and Natural Gas Sales. Arena's oil and natural gas sales revenue increased approximately $108.8 million to $208.9 million in 2008. Oil sales increased $102.1 million and natural gas sales increased $6.7 million. The oil sales increase was caused by a sales volume increase of 702,310 barrels in 2008, and a 41% increase in the average realized per barrel oil price from $66.82 in 2007 to $94.16 in 2008. These per barrel amounts were calculated by dividing revenue from oil sales by the volume of oil sold, in barrels. The natural gas sales increase was caused by a sales volume increase of 408,102 Mcf in 2008, and a 23% increase in the average realized per barrel oil price from $8.02 in 2007 to $9.84 in 2008. These per Mcf amounts were calculated by dividing revenue from gas sales by the volume of gas sold, in Mcf. The volume increase for crude oil and natural gas primarily resulted from development of existing properties in 2008.

Oil and Gas Production Costs. Aggregate oil and gas production costs increased from $11.5 million in 2007 to $17.8 million and increased on a Boe basis from $7.34 in 2007 to $7.63 in 2008. These per Boe amounts were calculated by dividing total production costs by total volume sold, in Boe. This aggregate increase was the result of the drilling of new wells in 2008 and cost increases. The increase on a per Boe basis was attributable to rising rates for labor and services.

Oil and Gas Production Taxes. Oil and gas production taxes as a percentage of oil and natural gas sales were 5.65% during 2007 and decreased to 5.04% in 2008.

Realized Loss on Oil Derivative. Realized loss on oil derivative increased from $0.9 million in 2007 to $4.3 million in 2008. This increase was the result of commodity price increases during most of 2008.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased by $11.9 million to $30.1 million in 2008. The increase was a result of an increase in the average depreciation, depletion and amortization rate from $11.59 per Boe during 2007 to $12.88 per Boe during

2008. These per Boe amounts were calculated by dividing total depreciation, depletion and amortization expense by total volume sold, in Boe. The increased depreciation, depletion and amortization were the result of increased sales volume and an increase in estimated future development costs.

General and Administrative Expenses. General and administrative expenses increased by $5.7 million to $13.6 million during 2008. This increase was primarily related to increases in compensation expense associated with an increase in personnel required to administer growth and compensation expense related to Arena's stock option plan.

Interest Income. Interest income increased $0.4 million to $1.3 million in 2008. The increase was due to higher cash balances during periods of the year in 2008.

Interest Expense. Interest expense decreased $0.3 million to $1.1 million in 2008. The increase was due to lower amounts of debt being outstanding during periods of the year in 2008.

Income Tax Expense. Arena's effective tax rate was 37% during 2008 and 38% during 2007.

Net Income. Net income increased from $34.4 million for 2007 to $83.6 million for 2008. The primary reasons for this increase include higher crude oil and natural gas prices between periods and an increase in volumes sold, partially offset by higher oil and gas production costs, oil and gas production taxes and general and administrative expenses due to growth.

Arena's Historical Liquidity

Arena's primary sources of cash were cash flows from operations and equity offerings. During the three years ended December 31, 2009, Arena generated $349.5 million from operating activities and financed $222.4 million through proceeds from the sale of stock and warrants and exercise of warrants and options. Arena primarily used this cash generation to fund its capital expenditures and development aggregating $497.8 million over the three years ended December 31, 2009. At December 31, 2009, Arena had cash on hand of $63.6 million and working capital of $62.4 million, compared to December 31, 2008 when Arena had cash of $58.5 million and working capital of $69.7 million.

Arena's Historical Critical Accounting Policies and Estimates

The discussion of Arena's historical financial condition and results of operations set forth above is based upon the information reported in Arena's periodic reports filed with the SEC, including Arena's financial statements. The preparation of these statements required Arena to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities at the date of the financial statements. Arena based its assumptions and estimates on historical experience and other sources it believed to be reasonable at the time. Arena's historical significant accounting policies are detailed in Note 1 to its financial statements included in this prospectus.

SandRidge Permian Trust

The Trust's Liquidity and Capital Resources

On a pro forma basis after giving effect to the closing of the offering and the transactions described in "The Trust Formation Transactions," the trust's principal sources of liquidity will be distributions it receives from SandRidge pursuant to the Term Royalties and the Perpetual Royalties, as well as cash received pursuant to the hedging arrangements. The trust's principal uses of cash will be to make distributions to trust unitholders in accordance with the trust agreement, to make cash payments that may be required pursuant to the hedging arrangements, and to pay the trust's administrative expenses. The trust will not have any capital expenditures or other capital commitments. If the trustee determines that cash on hand and cash expected to be received are insufficient to cover the trust's liabilities, the trustee may cause the trust to borrow funds required to pay the liabilities. The trust may borrow the funds from any person, including the trustee or its affiliates. If the trust borrows funds, the trust unitholders will not receive distributions until the borrowed funds are repaid.

The trustee intends to withhold $1.0 million from the first distribution to unitholders to establish a cash reserve available to the trustee to pay trust administrative expenses. If the trustee uses such cash reserve (or any portion thereof) to pay or reimburse trust liabilities or expenses, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until the cash reserve is replenished. This cash reserve will be part of the trust estate and will bear interest at the same rate as other cash on hand in the trust estate. Upon the dissolution of the trust, the balance of the cash reserve (including accrued interest thereon) will be distributed to trust unitholders on a pro rata basis.

In addition, SandRidge has agreed that, if at any time the trust's cash on hand (including available cash reserves) is not sufficient to pay the trust's ordinary course administrative expenses as they become due, SandRidge will loan funds to the trust necessary to pay such expenses. Any funds loaned by SandRidge pursuant to this commitment will be made for the purpose of paying current accounts payable or other obligations to trade creditors in connection with obtaining goods or services or paying other accrued current liabilities arising in the ordinary course of the trust's business, and may not be used to satisfy trust indebtedness. If SandRidge loans funds pursuant to this commitment, unless SandRidge agrees otherwise, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid. Any such loan will be on an unsecured basis, and the terms of such loan will be substantially the same as those which would be obtained in an arms' length transaction between SandRidge and an unaffiliated third party.

The Trust's Critical Accounting Policies and Estimates

The following is a summary of the significant accounting policies followed by the trust.

Basis of Accounting. The trust follows the "modified cash basis" of accounting. This means the financial statements of the trust are prepared on the following basis:

- Revenues are recorded when received and distributions to trust unitholders are recorded when declared.
- Trust expenses are recorded when paid.
- Cash reserves may be established for certain contingencies that would not generally be recorded under generally accepted accounting principles.
- Amortization of the investment in royalty interests is calculated on the units of production method. Such amortization is charged directly to the trust corpus, and does not affect cash earnings.

While the trust's financial statements included in this prospectus differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"), the modified cash basis of reporting revenues, expenses and distributions is considered to be the most meaningful because quarterly distributions to the trust unitholders are based on net cash receipts. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the SEC as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

Most accounting pronouncements apply to entities whose financial statements are prepared in accordance with GAAP, directing such entities to accrue or defer revenues and expenses in a period other than when such revenues were received or expenses were paid. Because the trust's financial statements are prepared on the modified cash basis as described above, most accounting pronouncements are not applicable to the trust's financial statements.

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Distributable Income. Income determined on a GAAP basis would include all expenses incurred for the period presented. However, the trust serves as a pass-through entity, with expenses for depletion, interest and income taxes, other than the Texas franchise tax to which the trust is subject, being based upon the status and elections of the trust unitholders. In addition, the royalty interests will not be burdened by field and lease operating expenses. Thus, the trust's pro forma statement of distributable income purports to show distributable income, defined as income of the trust available for distribution to the trust unitholders before application of those unitholders' additional expenses, if any, for depreciation, depletion and amortization, interest and income taxes. The trust's revenues are reflected net of existing royalties and overriding royalties and have been reduced by gathering and any other post-production expenses. Actual cash receipts may vary due to timing delays of actual cash receipts from the property purchasers and due to wellhead and pipeline volume balancing agreements or practices.

Impairment of Royalty Interest. Investment in royalty interests will be assessed to determine whether net capitalized cost is impaired whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment is indicated when the net capitalized costs of the investment in royalty interests exceeds undiscounted future net revenues attributable to the proved oil and natural gas reserves of the trust's royalty interests. The trust will provide a write-down to the extent that the net capitalized costs exceed the fair value of the proved oil and natural gas reserves attributable to the trust's royalty interests. Any such write-down would be charged directly to trust corpus and would not reduce distributable income.

Effects of Inflation and Pricing

The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry puts extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Material changes in prices impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans and value of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. Arena experienced increases and decreases in costs during 2009 due to fluctuating demand for oil field products and services as a result of fluctuating oil and natural gas prices. The trust anticipates costs will vary in accordance with commodity prices for oil and natural gas, and the associated increase or decrease in demand for services related to production and exploration.

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THE UNDERLYING PROPERTIES

The Underlying Properties consist of the working interest owned by SandRidge in the Permian Basin in Andrews County, Texas arising under leases and farmout agreements related to properties from which the PDP Royalty Interest and the Development Royalty Interest will be conveyed. SandRidge acquired the Underlying Properties in July 2010 as part of its acquisition of Arena, and it expects to operate substantially all of the Underlying Properties. Arena acquired its working interests in a large portion of the Underlying Properties in 2004, and acquired interests in additional Underlying Properties from 2005 through 2009. Initial production of hydrocarbons from the Underlying Properties began prior to 1975. The Underlying Properties consist of approximately 16,800 gross acres (15,900 net acres), which SandRidge estimates provides approximately three times the acreage required to fulfill SandRidge's drilling obligation under the development agreement. The reserves attributable to the trust's royalty interests include the reserves that are expected to be produced from the Permian Basin during the 20-year period in which the trust owns the royalty interests as well as the residual interest in the reserves that the trust will sell on or shortly following the Termination Date. As of March 31, 2011 and after giving effect to the conveyance of the PDP Royalty Interest and the Development Royalty Interest to the trust, the total reserves estimated to be attributable to the trust were 21.8 MMBoe. This amount includes 5.8 MMBoe attributable to the PDP Royalty Interest and 16.0 MMBoe attributable to the Development Royalty Interest, respectively. SandRidge is currently the operator of all of the wells subject to the PDP Royalty Interest. The reserves consist of 96% liquids (87% oil and 9% natural gas liquids) and 4% natural gas.

Overview of Underlying Properties

The Underlying Properties are located in the greater Fuhrman-Mascho field area, a region in Andrews County, Texas that produces oil from the Grayburg/San Andres formation within the Permian Basin. SandRidge currently operates three drilling rigs within the AMI and, as of March 31, 2011, had drilled 101 wells since acquiring the properties in July 2010. Within the AMI, SandRidge operates 509 wells and has 888 proven undeveloped locations as of March 31, 2011. These 888 proven locations are a combination of 5-acre, 10-acre and 20-acre infill spacing locations. As of March 31, 2011, average daily production from the Underlying Properties was approximately 3,400 Boe/d.

Permian Basin. The Permian Basin extends throughout southwest Texas and southeast 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 U.S. crude oil production, making this basin the second largest oil producing area 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.

SandRidge currently operates approximately 2,600 gross producing wells in the Permian Basin, with an average working interest of 94%. SandRidge's average daily net production for the month of March 2011 in the Permian Basin was approximately 28,800 Boe/d. SandRidge was operating 16 rigs in the basin as of March 2011. SandRidge drilled 484 wells in this area in 2010 and expects to drill over 800 wells in 2011.

Fuhrman-Mascho Field. The Fuhrman-Mascho field is located near the center of the Central Basin Platform in the Permian Basin. The field 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 since its discovery in 1930, the field has produced approximately 142 MMBoe. SandRidge currently operates eight drilling rigs in the area and has drilled 307 wells as of March 31, 2011 since acquiring the properties in July 2010.

Oil, Natural Gas and Natural Gas Liquids Reserves

Netherland Sewell estimated oil, natural gas and natural gas liquids reserves attributable to the Underlying Properties as of March 31, 2011. Numerous uncertainties are inherent in estimating reserve

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volumes and values, and the estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of the reserves may vary significantly from the original estimates.

Proved reserves of the Underlying Properties and royalty interests. The following table sets forth certain estimated proved reserves and the PV-10 value as of March 31, 2011 attributable to the Underlying Properties and the royalty interests, in each case derived from the reserve report. The reserve report was prepared by Netherland Sewell in accordance with criteria established by the SEC.

Proved reserve quantities attributable to the royalty interests are calculated by multiplying the gross reserves for each property by the royalty interest assigned to the trust in each property. The net revenues attributable to the trust's reserves are net of an assumed level of post-production costs based on historical results. The reserves related to the Underlying Properties include all of the proved reserves expected to be economically produced from the Permian Basin during the life of the properties. The reserves and revenues attributable to the trust's interests include only the reserves attributable to the Underlying Properties that are expected to be produced within the 20-year period in which the trust owns the royalty interest as well as the residual interest in the reserves that the trust will own on the Termination Date. The reserve report is included as Annex A to this prospectus.

	Proved Reserves(1)			
	Oil (MBbl)(2)	Natural Gas (MMcf)	Total (MBoe)	PV-10 Value(3) (Dollars in millions)
Underlying Properties	30,644	7,215	31,847	$ 580.8
Royalty Interests:				
PDP Royalty Interests (80%)(4)	5,577	1,375	5,806	$ 213.7
Development Royalty Interests (70%)	15,401	3,570	15,996	555.8
Total	20,977	4,945	21,802	$ 769.5

(1)
The proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil and natural gas for the period from April 1, 2010 through March 1, 2011, without giving effect to derivative transactions, and were held constant for the life of the properties. The prices used in the reserve report, as well as SandRidge's internal reports, yield weighted average prices at the wellhead, which are based on first-day-of-the-month reference prices and adjusted for transportation and regional price differentials. The reference prices and the equivalent weighted average wellhead prices are both presented in the table below.

	Reference prices		Weighted average wellhead prices	
	Oil (per Bbl)	Natural gas (per Mcf)	Oil (per Bbl)	Natural gas (per Mcf)
March 31, 2011	$ 80.04	$ 4.102	$ 75.58	$ 3.003

(2)
Includes natural gas liquids.

(3)
PV-10 is the present value of estimated future net revenue to be generated from the production of proved reserves, discounted using an annual discount rate of 10%, calculated without deducting future income taxes. PV-10 is a non-GAAP financial measure and generally differs from standardized measure of discounted net cash flows, or Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Because the historical financial information related to the Underlying Properties consists solely of revenues and direct operating expenses and does not include the effect of income taxes, we expect the PV-10 and Standardized Measure attributable to the Underlying Properties for each period to be

equivalent. Because the trust will not bear federal income tax expense, we also expect the PV-10 and Standardized Measure attributable to the royalty interests for each period to be equivalent. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Underlying Properties or the royalty interests. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(4) Includes reserves associated with wells in the process of being completed.

Information concerning historical changes in net proved reserves attributable to the Underlying Properties, and the calculation of the standardized measure of discounted future net revenues related thereto, is contained in the unaudited supplemental information contained elsewhere in this prospectus. SandRidge has not filed reserve estimates covering the Underlying Properties with any other federal authority or agency.

The Reserve Report

All of the oil, natural gas and natural gas liquids reserves in this registration statement were estimated by Netherland Sewell. The process to review and estimate the reserves began with a staff reservoir engineer 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, and geosciences data. This data was reviewed by various levels of SandRidge management for accuracy, before consultation with Netherland Sewell. These individuals consulted regularly with Netherland Sewell during the reserve estimation process to review properties, assumptions, and any new data available. Internal reserve estimates and methodologies were compared to Netherland Sewell to test the reserve estimates and conclusions before the reserve estimates were included in this registration statement. Additionally, SandRidge's senior management reviewed and approved the reserve report contained herein.

Internal Controls. SandRidge's Executive Vice President Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of the company's reserve estimates, is the primary contact with Netherland Sewell and received the reserve report from Netherland Sewell. He has a Bachelor of Science degree in Mechanical Engineering with 30 years of practical industry experience, including 25 years of estimating and evaluating reserve information. In addition, SandRidge'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 and makes 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 16 full-time employees, comprised of six degreed engineers and 10 engineering analysts/technicians with a minimum of a four-year degree in mathematics, economics, finance or other business or science field.

SandRidge maintains a continuous education program for 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 made by experienced reservoir engineers or under their direct supervision.

- The Reservoir Engineering Department reports directly to the President, independently from all of SandRidge's operating divisions.

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The Reservoir Engineering Department follows comprehensive SEC-compliant internal policies to determine and report proved reserves including:

- confirming that reserve 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 reserve estimates to those prepared by third parties.

Each quarter, the Executive Vice President Reservoir Engineering presents the status of SandRidge's reserves, including the reserves associated with the Underlying Properties, to the Executive Committee, 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.

SandRidge's Reservoir Engineering Department works closely with its independent petroleum consultants at each fiscal year end to ensure the integrity, accuracy and timeliness of an annually developed independent reserves estimate. These independently developed reserves estimates are adopted as SandRidge'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 interviews the third-party engineer at Netherland Sewell primarily responsible for the reserve report.

Technologies. The reserve report was 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. The continuity of the formation across the AMI was established by reviewing electric well logs, geologically mapping the analogous reservoir and reviewing extensive production data from 496 wells. The reserves attributable to the Producing Wells, which cover a wide area of the AMI, and the continuity of the formation over the AMI further support proved undeveloped classification within close proximity to the Producing Wells. Data from SandRidge demonstrates a consistency in this formation over an area much larger than the AMI. In addition, direct measurement from producing wells has been used to confirm consistency in reservoir properties such as porosity, thickness and stratigraphic conformity.

The proven undeveloped locations within the AMI are generally all offsets to the wells drilled and producing to date. Of the proved undeveloped drilling locations identified in the reserve report, only approximately 6% are not direct offsets of other historically producing wells. Those approximately 6% proved undeveloped drilling locations are generally characterized by the second offset interior to known production.

Netherland Sewell. Netherland Sewell, the independent petroleum engineering consultant, estimated all of the proved reserve information in this registration statement, in accordance with the definitions and guidelines of the SEC and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas. For the purposes of the reserve report, Netherland Sewell used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in the reserve report have been estimated using deterministic methods. Netherland Sewell used standard engineering and geosciences methods, or a combination of methods, such as performance analysis and analogy, that they considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and guidelines. A substantial portion of these reserves are for undeveloped locations and producing wells that lack sufficient production history upon which

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performance-related estimates of reserves can be based. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics.

Netherland Sewell's expertise is in petroleum engineering, geoscience, and petrophysical interpretation, not legal or accounting matters; they are not accountants, attorneys, or landmen. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, the conclusions from Netherland Sewell necessarily represent only informed professional judgment. The titles to the properties have not been examined by Netherland Sewell, nor has the actual degree or type of interest owned been independently confirmed. The data used in Netherland Sewell's estimates were obtained from SandRidge and the non-confidential files of Netherland Sewell and were accepted as accurate. Supporting geoscience, field performance, and work data are on file in their office.

The qualifications of the technical person at Netherland Sewell primarily responsible for overseeing his firm's preparation of the reserve estimates presented herein include: 29 years of practical experience in petroleum engineering and more than 12 years estimating and evaluating reserve information; 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. These qualifications meet or exceed the Society of Petroleum Engineers standard requirements to be a professionally qualified Reserve Estimator and Auditor.

Netherland Sewell are independent petroleum engineers, geologists, geophysicists, and petrophysicists; Netherland Sewell does not own an interest in these properties and are not employed on a contingent basis.

Additional Information Regarding the Arena Properties

Drilling Activity. The following table sets forth information with respect to the wells completed by Arena or SandRidge on the Underlying Properties during the periods indicated. SandRidge acquired Arena in July 2010. 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 Arena or SandRidge had a working interest and net wells refer to gross wells multiplied by SandRidge's or Arena's weighted average working interest. As of December 31, 2010, there were 7 gross (5.9 net) wells drilling or awaiting completion.

	2010				2009				2008			
	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent	Gross	Percent	Net	Percent
Development:												
Productive	155	100%	152.2	100%	71	100%	70.5	100%	57	100%	56.3	100%
Dry	0		0		0		0		0		0	
Total	155	100%	152.2	100%	71	100%	70.5	100%	57	100%	56.3	100%
Exploratory:												
Productive	0		0		0		0		0		0	
Dry	0		0		0		0		0		0	
Total	0		0		0		0		0		0	
Total:												
Productive	155	100%	155.2	100%	71	100%	70.5	100%	57	100%	56.3	100%
Dry	0		0		0		0		0		0	
	155	100%	152.2	100%	71	100%	70.5	100%	57	100%	56.3	100%

Productive Wells. The following table sets forth the number of productive wells within the AMI in which SandRidge owned working interests as of March 31, 2011 and from which SandRidge will convey the royalty interests to the trust. Productive wells consist of producing wells and wells capable of producing,

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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 SandRidge has an interest and net wells are the sum of SandRidge's fractional working interests owned in gross wells.

	Oil		Natural Gas		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Productive Wells	509	497.2	0	0	509	497.2

Developed and Undeveloped Acreage. The following table sets forth information regarding developed and undeveloped acreage held by SandRidge within the AMI as of July 19, 2011:

	Developed Acreage(1)		Undeveloped Acreage(2)	
	Gross(3)	**Net(4)**	**Gross(3)**	**Net(4)**
Acreage Held by SandRidge within the AMI	8,214	7,962	8,632	7,939

(1) Developed acres are acres spaced or assigned to productive wells.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

(3) A gross acre is an acre in which SandRidge owns a working interest. The number of gross acres is the total number of acres in which SandRidge owns a working interest.

(4) A net acre is deemed to exist when the sum of SandRidge's fractional ownership working interests in gross acres equals one. The number of net acres is the sum of SandRidge's fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases comprising the 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 July 14, 2011 the expiration periods of the gross and net acres that are subject to leases in the acreage summarized in the above table.

	Acres Expiring	
Twelve Months Ending	**Net**	**Gross**
December 31, 2011	162	920
December 31, 2012	332	801
December 31, 2013	136	800
December 31, 2014	16	200
December, 2015 and later		
Total	646	2,721

Properties Underlying the Development Royalty Interest

SandRidge's average net revenue interest in the oil and natural gas properties underlying the Development Royalty Interest is approximately 69.3%. The Development Royalty Interest will entitle the trust to receive 70% of the proceeds attributable to SandRidge's net revenue interest in future production of oil and natural gas resulting from the drilling of the Development Wells, with 35% of such proceeds attributable to the Term Development Royalty and 35% of such proceeds attributable to the Perpetual Development Royalty.

SandRidge owns a majority working interest in substantially all of the locations on which it expects to drill the Development Wells, and it expects to operate such wells during the subordination period. Except as described in "The Trust Development Agreement and Drilling Support Lien," until such time as SandRidge has met its commitment to drill the Development Wells, SandRidge will covenant and agree not to drill and complete, and will not permit any other person within its control to drill and complete, any well in the AMI for its own account. Upon the trustee's release of the Drilling Support Lien, SandRidge will further agree not to drill and complete, and will not permit any other person within its control to drill and complete, any well in the AMI that will have a perforation that will be within 170 feet of any perforation of any Development Well or Producing Well.

If SandRidge drills one or more Development Wells in which it has less than a 69.3% net revenue interest, it may drill, or cause to be drilled, additional wells above the planned number for the trust in order to make the total number of Development Wells equal 888. For instance, if SandRidge drilled one well in which it has a 52.0% net revenue interest (assuming it was drilled and completed in the Grayburg/San Andres formation), such well would count for purposes of the development agreement as only .75 Development Wells (i.e., 52.0% / 69.3%). In order to compensate for this, SandRidge could drill, or cause to be drilled, an additional well (assuming it was drilled and completed in the Grayburg/San Andres formation) with a 86.6% net revenue interest (i.e., 86.6% / 69.3%) so that the trust receives 1.25 Development Wells. In addition, SandRidge may receive additional credit for drilling horizontal Development Wells. See "The Trust Development Agreement and Drilling Support Lien."

SandRidge may, in its sole discretion, make additional acreage or interests or acreage exchanged for other acreage in the AMI subject to the Development Royalty Interest, so long as the aggregate additional acreage or interests or exchanged acreage does not exceed five percent of the acreage currently subject to the Development Royalty Interest. See "Description of the Royalty Interests Additional Features of the Royalty Interests."

Sale and Abandonment of the Underlying Properties

SandRidge and any transferee will have the right to abandon its interest in any well or property comprising a portion of the Underlying Properties if, in its opinion, such well or property ceases to produce or is not capable of producing in commercially paying quantities. To reduce or eliminate the potential conflict of interest between SandRidge and the trust in determining whether a well is capable of producing in commercially paying quantities, SandRidge and any transferee, as applicable, will be required under the applicable conveyance to act as a reasonably prudent operator in the AMI under the same or similar circumstances would act if it were acting with respect to its own properties, disregarding the existence of the royalty interests as a burden affecting such properties.

After completion of its drilling obligation, SandRidge generally may sell all or a portion of its interests in the Underlying Properties, subject to and burdened by the royalty interests, without the consent of the trust unitholders. In addition, SandRidge may, without the consent of the trust unitholders, require the trust to release for sale royalty interests with an aggregate value to the trust not to exceed $5.0 million during any 12-month period. These releases will be made only in connection with a sale by SandRidge of Underlying Properties and are conditioned upon the trust receiving an amount equal to the fair value to the trust of such royalty interests. Any net sales proceeds paid to the trust are distributable to trust unitholders for the quarter in which they are received. SandRidge has not identified for sale any of the Underlying Properties.

Marketing and Post-Production Services

Pursuant to the terms of the conveyances creating the royalty interests, SandRidge will have the responsibility to market, or cause to be marketed, the oil, natural gas and natural gas liquids production related to the Underlying Properties. The terms of the conveyances creating the royalty interests do not permit SandRidge to charge any marketing fee when determining the proceeds upon which the royalty payments will be calculated. As a result, the proceeds to the trust from the sales of oil, natural gas and natural gas liquids production from the Underlying Properties will be determined based on the same price (net of post-production costs) that SandRidge receives for oil, natural gas and natural gas liquids production attributable to SandRidge's remaining interest in the Underlying Properties.

A wholly owned subsidiary of SandRidge markets the majority of SandRidge's operated production. Such subsidiary enters into oil, natural gas and natural gas liquids sales arrangements with large aggregators of supply and these arrangements may be on a month-to-month basis or may be for a term of up to one year or longer. The oil, natural gas and natural gas liquids is sold at a market price and subsequently any applicable post-production costs will be deducted. The primary aggregators of supply with whom SandRidge currently does business in the AMI are Enterprise Crude Oil LLC, ConocoPhillips Company and DCP Midstream, LP.

Following this offering, post-production costs will be deducted from proceeds paid to the trust. SandRidge may provide post-production services itself or contract with others to provide post-production services, including gathering, transportation, processing and other reasonable post-production services, including transportation on downstream interstate pipelines. Such post-production costs will be expressed either (1) as a cost per Bbl or MMBtu or (2) as a percentage of the gross production from a well. The trust's cash available for distribution will be reduced by SandRidge's deductions for these post-production costs.

Post-production costs may be deducted by the ultimate purchaser of the oil, natural gas and natural gas liquids prior to payment being made to SandRidge or its marketing affiliate for such production. At other times, SandRidge or its marketing affiliate will make payments directly to the third parties providing such post-production services. In either instance, the trust's cash available for distribution will be reduced by the costs paid by SandRidge for such post-production services provided by third parties. If the post-production costs are expressed as a percentage of the gross production from a well, then the volume of production from that well actually available for sale is less the applicable percentage charged, and as a result the reserves associated with that well that are attributable to the royalty interest are reduced accordingly.

The cost of marketing and post-production services is included within the assumed differentials from NYMEX pricing discussed above under "Target Distributions and Subordination and Incentive Thresholds."

Regardless of whether the post-production costs are based upon a cost per Bbl or per MMBtu or a percentage of gross production from a well, such costs may increase or decrease in the future. The post-production costs attributable to third party arrangements may be costs established by arms-length negotiations or pursuant to a state or federal regulatory proceeding. SandRidge will be permitted to deduct from the proceeds available to the trust other post-production costs necessary to make the oil, natural gas and natural gas liquids from the Underlying Properties marketable, so long as such costs do not materially exceed the charges prevailing in the area for similar services.

SandRidge expects to enter into oil, natural gas and natural gas liquids supply arrangements and post-production service arrangements for the oil, natural gas and natural gas liquids to be produced from the Development Wells that are similar to those in place with respect to the Producing Wells. Any new oil, natural gas and natural gas liquids supply arrangements or those entered into for providing post-production services, will be utilized in determining the proceeds for the Underlying Properties.

Title to Properties

The Underlying Properties are subject to certain burdens that are described in more detail below. To the extent that these burdens and obligations affect SandRidge's rights to production and the value of production from the Underlying Properties, they have been taken into account in calculating the trust's interests and in estimating the size and the value of the reserves attributable to the royalty interests.

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SandRidge acquired its interests in the Underlying Properties in July 2010 as part of its acquisition of Arena. Arena acquired its working interests in a large portion of the Underlying Properties in 2004, and acquired interests in additional Underlying Properties from 2005 through 2009, through a variety of means, including through the acquisition of oil and natural gas leases directly from the mineral owner, through assignments of oil and natural gas leases by the lessee who originally obtained the leases from the mineral owner, through farmout agreements that grant SandRidge the right to earn interests in the properties covered by such agreements by drilling wells, and through acquisitions of other oil and natural gas interests.

SandRidge's interests in the oil and natural gas properties comprising the Underlying Properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens, express and implied, under oil and natural gas leases;
- production payments and similar interests and other burdens created by SandRidge or its predecessors in title;
- a variety of contractual obligations arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors and contractual liens under operating agreements that are not yet delinquent or, if delinquent, are being contested in good faith;
- pooling, unitization and communitization agreements, declarations and orders;
- easements, restrictions, rights-of-way and other matters that commonly affect real property;
- conventional rights of reassignment that obligate SandRidge to reassign all or part of a property to a third party if SandRidge intends to release or abandon such property; and
- rights reserved to or vested in the appropriate governmental agency or authority to control or regulate the Underlying Properties.

SandRidge believes that the burdens and obligations affecting the Underlying Properties and the royalty interests are conventional in the industry for similar properties. SandRidge also believes that the burdens and obligations do not, in the aggregate, materially interfere with the use of the Underlying Properties and will not materially adversely affect the value of the royalty interest.

SandRidge believes that its title to the Underlying Properties is, and the trust's title to the royalty interests will be, good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions as are not so material as to detract substantially from the use or value of such properties or royalty interests. Consistent with industry practice, SandRidge has not yet obtained drilling title opinions on the properties upon which SandRidge intends to drill the Development Wells. SandRidge does not intend to perform any further title examination prior to the closing of the offering being made hereby. Frequently, as a result of title examinations, certain curative work must be done to correct identified title defects, and such curative work entails time and expense. SandRidge will not be relieved of its obligation to drill a well if title defects are identified that prevent SandRidge from drilling in such drill site.

Insurance

In accordance with industry practice, SandRidge maintains insurance against some, but not all, of the operating risks to which its business is exposed. SandRidge currently has insurance policies that include coverage for general liability (includes sudden and accidental pollution), physical damage to its oil and gas properties, operational control of offshore wells, aviation, auto liability, marine liability, worker's compensation and employer's liability, among other things. At the depths and in the areas in which SandRidge operates, and in light of the vertical and horizontal drilling that it undertakes, SandRidge typically does not encounter high pressures or extreme drilling conditions. Accordingly, SandRidge does not carry control of well insurance for onshore operations.

Currently, SandRidge has general liability insurance coverage up to $1 million per occurrence, which includes sudden and accidental environmental liability coverage for the effects of pollution on third parties arising from its operations. SandRidge's insurance policies contain maximum policy limits and in most cases, deductibles (generally ranging from $25,000 to $1 million) that must be met prior to recovery. These insurance policies are subject to certain customary exclusions and limitations. In addition, SandRidge maintains $100 million in excess liability coverage, which is in addition to and triggered if the general liability per occurrence limit is reached.

SandRidge requires all of its third-party contractors to sign master service agreements in which they agree to indemnify SandRidge for injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider. Similarly, SandRidge generally agrees to indemnify each third-party contractor against claims made by employees of SandRidge and SandRidge's other contractors. Additionally, each party generally is responsible for damage to its own property.

The third-party contractors that perform hydraulic fracturing operations for SandRidge sign the master service agreements containing the indemnification provisions noted above. SandRidge does not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. However, SandRidge believes its general liability and excess liability insurance policies would cover third party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies.

SandRidge re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that SandRidge will be able to maintain insurance in the future at rates that it considers reasonable and SandRidge may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Competition and Markets

The oil and natural gas industry is highly competitive. SandRidge competes with major oil and gas companies and independent oil and gas companies for leases, equipment, personnel and markets for the sale of oil, natural gas and natural gas liquids. Many of these competitors are financially stronger than SandRidge, but even financially troubled competitors can affect the market because of their need to sell oil, natural gas and natural gas liquids at any price to attempt to maintain cash flow. The trust will be subject to the same competitive conditions as SandRidge and other companies in the oil and gas industry.

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

Future price fluctuations for oil, natural gas and natural gas liquids will directly impact trust distributions, estimates of reserves attributable to the trust's interests, and estimated and actual future net revenues to the trust. In view of the many uncertainties that affect the supply and demand for oil, natural gas and natural gas liquids, neither the trust nor SandRidge can make reliable predictions of future supply and demand for oil, natural gas and natural gas liquids, future oil, natural gas and natural gas liquids prices or the effect of future oil, natural gas and natural gas liquids prices on the trust.

Regulation

Oil and Natural Gas Regulation. The availability, terms and cost of transportation significantly affect sales of oil, natural gas and natural gas liquids. The interstate transportation and sale for resale of oil,

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natural gas and natural gas liquids 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. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The Federal Energy Regulatory Commission's regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Sales of oil, natural gas and natural gas liquids are not currently regulated and are made at market prices. Although oil, natural gas and natural gas liquids prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. Neither SandRidge nor the trust can predict whether new legislation to regulate oil, natural gas and natural gas liquids prices might be proposed, what proposals, if any, might actually be enacted by Congress or state legislatures, and what effect, if any, the proposals might have on the operations of the Underlying Properties.

Environmental Regulation. The exploration, development and production of oil, natural gas and natural gas liquids are subject to federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, 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 SandRidge's operations or attributable to former operations; 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.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, 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 proceeds available to the trust under the royalty interests. Moreover, accidental releases or spills may occur in the course of SandRidge's operations on the Underlying Properties, and there can be no assurance that SandRidge 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, 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 SandRidge's operation of the Underlying Properties.

Hazardous Substances and Wastes. The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("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 found 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 and property damage allegedly caused by the release of hazardous substances into the environment. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. SandRidge generates materials in the course of its operations, including with respect to the Underlying Properties, that may be regulated as hazardous substances.

SandRidge generates wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("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 most of the other wastes associated with the exploration, production and development of crude oil, natural gas and natural gas liquids are currently exempt from regulation as hazardous wastes under RCRA. However, it is possible that certain oil, natural gas and natural gas liquids 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 with the EPA requesting them to reconsider 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, which could have a material adverse effect on the cash distributions to the trust unitholders. In the course of its operations, SandRidge generates petroleum hydrocarbon wastes and ordinary industrial wastes that are subject to regulation under the RCRA. SandRidge is in substantial compliance with all regulations regarding the handling and disposal of oil and gas exploration and production wastes from its operations, including with respect to the Underlying Properties.

SandRidge currently owns or leases, and in the past may have owned or leased, properties that have been used to explore for and produce oil, natural gas and natural gas liquids. Although SandRidge may have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by SandRidge or on or under the 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 was not under SandRidge's control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, SandRidge could be required to remove or remediate previously disposed wastes, to 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.

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 monitoring and reporting requirements. These laws and regulations may require SandRidge 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, natural gas and natural gas liquids projects. While SandRidge may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues, SandRidge does not believe that such requirements will have a material adverse effect on its ability to satisfy its obligations to the trust.

Water Discharges. The Federal Water Pollution Control Act, as amended ("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. 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.

Climate Change. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and certain other 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 federal Clean Air Act. Accordingly, the EPA has adopted regulations that require a reduction in emissions of GHGs from motor vehicles and also trigger permit review for GHG emissions from certain large stationary sources. The EPA's rules relating to emissions of GHGs from large 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, in October 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including sources emitting more than 25,000 tons of GHGs on an annual basis, beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA published a final rule that expands its October 2009 final rule on reporting of GHG emissions to require certain owners and operators of onshore oil, natural gas and natural gas liquids production to monitor greenhouse gas emissions beginning in 2011 and to report those emissions beginning in 2012. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG gases from, SandRidge's equipment and operations could require SandRidge to incur costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the oil, natural gas and natural gas liquids it produces. Finally, it should be noted that 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, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on SandRidge's assets and operations.

In addition, Congress has actively 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 implementing regulations that may be adopted to address GHG emissions could require SandRidge to incur increased operating costs, could adversely affect demand for the oil, natural gas and natural gas liquids that it produces, and could have a material adverse effect on SandRidge's business, financial condition and results of operations.

Endangered Species. The federal Endangered Species Act ("ESA") restricts activities that may affect endangered or threatened species or their habitats. We believe our operations are in substantial compliance with the ESA. However, any future designation of previously unidentified species as endangered or threatened on properties where we operate could subject us to additional costs or cause our oil and gas activities to be subject to operating restrictions or bans.

Employee Health and Safety. The operations of SandRidge 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 SandRidge's operations and that this information be provided to employees, state and local government authorities and citizens. SandRidge believes that it is in substantial compliance with all applicable laws and regulations relating to worker health and safety.

State Regulation. Texas regulates the drilling for, and the production and gathering of, oil, natural gas and natural gas liquids, including requirements relating to drilling permits, the location, spacing and

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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, natural gas and natural gas liquids, the operation of wells, allowable rates of production, the use of fresh water in oil, natural gas and natural gas liquids operations, saltwater injection and disposal operations, the plugging and abandonment of wells and the restoration of surface properties, the prevention of waste of oil, natural gas and natural gas liquids resources, the protection of the correlative rights of oil, natural gas and natural gas liquids 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 SandRidge may drill, impact the locations at which SandRidge may drill wells, restrict the amounts of oil, natural gas and natural gas liquids that may be produced from SandRidge's wells and increase the costs of its operations. Realized prices for the first sale of oil, natural gas and natural gas liquids are not subject to state regulation in Texas.

Hydraulic Fracturing. Oil, natural gas and natural gas liquids may be recovered from the Underlying 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 recently asserted federal regulatory authority over certain hydraulic fracturing practices not currently employed by SandRidge in the AMI. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study anticipated to be available by late 2012 and final results by 2014. Also for the second consecutive session, legislation has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For instance, in June 2011, Texas adopted a law that requires disclosure to the Railroad Commission of Texas of the additives and other chemicals contained in hydraulic fracturing fluids used in the state, subject to certain trade secret protections. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the Texas state level, such legal requirements could make it more difficult or costly for SandRidge to perform fracturing to stimulate production in the play and thereby affect the determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, SandRidge's fracturing activities, including with respect to its operations at the Underlying Properties, could become subject to additional permit 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, natural gas and natural gas liquids that SandRidge is ultimately able to produce in commercial quantities from the Underlying Properties.

All of the acreage and undeveloped reserves within the AMI are subject to hydraulic fracturing procedures as the process is required to economically develop the Grayburg/San Andres formation. The hydraulic fracturing process is integral to SandRidge's overall drilling and completion costs in the AMI and represents approximately 25% of the total drilling/completion costs per well (or, approximately $125,000 per well).

The hydraulic fracturing activity is limited to the oil and gas bearing Grayburg/San Andres formation, which is found at depths of 4,000 to 5,000 feet from the surface in Andrews County, Texas. This county in West Texas comprises 1,501 square miles, with over 25,000 wells drilled to date. The Railroad Commission of Texas has defined potable water sources in this area as usable-quality ground water from the surface to a depth of 250 feet and water in the Santa Rosa formation in an interval between 1,100 and 1,600 feet.

SandRidge diligently reviews best practices and industry standards, and complies with all regulatory requirements in the protection of these 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.

Based on current drilling techniques, a typical fracturing procedure for a well in the Grayburg/San Andres formation uses approximately 82,600 gallons of fluid (81,500 gallons of which is fresh water) and approximately 9,100 gallons-equivalent of sand. By volume, fresh water makes up nearly 99% of the total fracturing fluid. Of the remaining 1% of fluid, approximately one third is comprised of material such as enzymes and Guar (a common food additive), and slightly more than two thirds is a combination of other chemicals.

In compliance with the law enacted in Texas in June 2011, SandRidge will disclose hydraulic fracturing data to the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission chemical registry. This disclosure is required for each chemical ingredient that is subject to the requirements of OSHA regulations, as well as the total volume of water used in the hydraulic fracturing treatment. A copy of the completed form will be submitted to the Railroad Commission of Texas with the completion report for the well. Additionally, a list of all other chemical ingredients not required by the registry will also be provided to the Railroad Commission for disclosure on a publicly accessible website. The Railroad Commission is currently in the process of writing the rules to implement the legislation and is required to have these rules implemented not later than July 1, 2012 for the registry components and not later than July 1, 2013 for the latter requirements.

There have not been any incidents, citations or suits related to SandRidge's hydraulic fracturing activities involving environmental concerns.

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DESCRIPTION OF THE ROYALTY INTERESTS

The royalty interests will be conveyed to the trust by SandRidge by means of conveyance instruments that will be recorded in the real property records of Andrews County, Texas and, if necessary, the real property records of any additional counties where the oil, natural gas and natural gas liquids to which the Underlying Properties relate are located.

The royalty interests will be conveyed from SandRidge's interest in the Producing Wells and the Development Wells. The PDP Royalty Interest entitles the trust to receive 80% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of production of oil, natural gas and natural gas liquids attributable to SandRidge's net revenue interest in the Producing Wells. The Development Royalty Interest entitles the trust to receive 70% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of production of oil, natural gas and natural gas liquids attributable to SandRidge's net revenue interest in the Development Wells.

The percentage of production proceeds to be received by the trust with respect to a well will equal the product of (1) the percentage of proceeds to which the trust is entitled under the terms of the conveyances (80% for the Producing Wells and 70% for the Development Wells) multiplied by (2) SandRidge's net revenue interest in the well. SandRidge on average owns a 73.0% net revenue interest in the Producing Wells. Therefore, the trust will have an average 58.4% net revenue interest in the Producing Wells. SandRidge on average owns a 69.3% net revenue interest in the properties in the AMI from which the Development Wells will be drilled and based on this net revenue interest, the trust would have an average 48.5% net revenue interest in the Development Wells. SandRidge's actual net revenue interest in any particular Development Well may differ from this average, and will depend on SandRidge's working interest and the royalty interests and similar revenue burdens owed to third parties with respect to such well.

PDP Royalty Interest

The PDP Royalty Interest entitles the trust to receive an amount of cash for each calendar quarter equal to 80% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Producing Wells. Proceeds from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Producing Wells in any calendar quarter means, for any calendar quarter commencing on or after April 1, 2011, the amount calculated based on actual production volumes attributable to SandRidge's net revenue interest in the Producing Wells, in each case after deducting the trust's proportionate share of:

- any taxes levied on the severance or production of the oil, natural gas and natural gas liquids produced from the Producing Wells and any property taxes attributable to the oil, natural gas and natural gas liquids produced from the Producing Wells; and

- post-production costs, which will generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and natural gas liquids produced, as applicable.

Proceeds payable to the trust from the sale of oil, natural gas and natural gas liquids production attributable to the Producing Wells in any calendar quarter will not be subject to any deductions for any expenses attributable to exploration, drilling, development, operating, maintenance or any other costs incident to the production of oil, natural gas and natural gas liquids production attributable to the Producing Wells, including any costs to plug and abandon a Producing Well.

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Development Royalty Interest

The Development Royalty Interest entitles the trust to receive an amount of cash for each calendar quarter equal to 70% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of estimated oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Development Wells. Proceeds from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Development Wells in any calendar quarter means, for any calendar quarter commencing on or after April 1, 2011, the amount calculated based on actual production volumes attributable to SandRidge's net revenue interest in the Development Wells, in each case after deducting the trust's proportionate share of:

- any taxes levied on the severance or production of the oil, natural gas and natural gas liquids produced from the Development Wells and any property taxes attributable to the oil, natural gas and natural gas liquids produced from the Development Wells; and

- post-production costs, which will generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and natural gas liquids produced, as applicable.

Proceeds payable to the trust from the sale of oil, natural gas and natural gas liquids production attributable to the Development Wells in any calendar quarter will not be subject to any deductions for any expenses attributable to exploration, drilling, development, operating, maintenance or any other costs incident to the production of oil, natural gas and natural gas liquids production attributable to the Development Wells, including any costs to drill a Development Well.

Sale of the Perpetual Royalties

The trust will begin to liquidate on the Termination Date and will soon thereafter wind up its affairs and terminate. The Term Royalties will automatically revert to SandRidge at the Termination Date, while the Perpetual Royalties will be sold and the proceeds thereof will be distributed to the unitholders at the Termination Date or soon thereafter. SandRidge will have a first right of refusal to purchase the Perpetual Royalties at the Termination Date.

The trust agreement provides that the trustee will use commercially reasonable efforts to retain a third-party advisor to market the Perpetual Royalties within 30 business days of the Termination Date. If the trustee receives a bona fide offer from a proposed purchaser other than SandRidge and wants to sell all or part of the Perpetual Royalties, it will be required to give notice (the "Offer Notice") to SandRidge, identifying the proposed purchaser and setting forth the proposed sale price, payment terms and other material terms and conditions under which the trustee is proposing to sell. SandRidge would then have 30 days from receipt of the Offer Notice to elect, by notice to the trustee, to purchase the subject properties offered for sale on the terms and conditions set forth in the Offer Notice. If SandRidge makes such election, the proposed purchaser would be entitled to receive reimbursement of its reasonable and documented expenses incurred in connection with its review and analysis of the subject properties and bid preparation. SandRidge and the trust would share equally the cost of reimbursement to the proposed purchaser.

If SandRidge does not give notice within the 30-day period following the Offer Notice, the trustee may, within 60 days, sell such properties to the identified purchaser on terms and conditions that are substantially the same as those previously set forth in such Offer Notice. Moreover, if, after a reasonable marketing period, no bid is received on any or all of the Perpetual Royalties from any party other than SandRidge, then SandRidge shall obtain, at the trust's expense, and deliver to the trustee, a fairness opinion from a nationally-recognized valuation firm with expertise in valuing oil, natural gas and natural gas liquids properties stating that the proposed sale price to be paid by SandRidge to the trust for the properties is fair to the trust.

Additional Features of the Royalty Interests

Reasonably Prudent Operator Standard. Under the conveyances, SandRidge is obligated to act as a reasonably prudent operator in the AMI under the same or similar circumstances as it would if it were acting with respect to its own properties, disregarding the existence of the royalty interests as burdens affecting such properties. Accordingly, there may be situations where SandRidge will drill on one or more potential drilling locations within the AMI that are not those identified locations underlying the reserve report.

True-up. The conveyances provide that if SandRidge's net revenue interest with respect to the Underlying Properties is greater than what was warranted to the trust in the conveyances, SandRidge will have the right to deduct from amounts owed to the trust the difference between what the trust actually receives from the royalty interests and what the trust should have received from the royalty interests had SandRidge's net revenue interest been the amount warranted in the conveyances. On the other hand, if SandRidge's net revenue interest with respect to the Underlying Properties is less than what was warranted to the trust in the conveyances, SandRidge must add to amounts owed to the trust the difference between what the trust actually receives from the royalty interests and what the trust should have received from the royalty interests had SandRidge's net revenue interest been the amount warranted in the conveyance.

Controversies. If a controversy arises as to the sales price of any production, then for purposes of determining gross proceeds:

- amounts withheld or placed in escrow by a purchaser are not considered to be received by the owner of the underlying property until actually collected;
- amounts received by the owner of the underlying property and promptly deposited with a nonaffiliated escrow agent will not be considered to have been received until disbursed to it by the escrow agent; and
- amounts received by the owner of the underlying property and not deposited with an escrow agent will be considered to have been received.

Overpayments. The trustee is not obligated to return any cash received from the royalty interests. Any overpayments made to the trust by SandRidge due to adjustments to prior calculations of proceeds or otherwise will reduce future amounts payable to the trust until SandRidge recovers the overpayments.

Sale of Underlying Properties. The conveyances generally permit SandRidge to sell, without the consent or approval of the trust unitholders, all or any part of its interest in the Underlying Properties, if the Underlying Properties are sold, subject to and burdened by the royalty interests. Notwithstanding the foregoing, the conveyances provide that SandRidge may not sell any of the Underlying Properties subject to the Development Royalty Interest until it has satisfied the drilling obligation pursuant to the terms of the development agreement. The trust unitholders are not entitled to any proceeds of any sale of SandRidge's interest in the Underlying Properties that remains subject to and burdened by the royalty interests. Following such sale, the royalties attributable to the transferred property will be calculated as described in this prospectus, and paid by the purchaser or transferee to the trust. As a result, any additional costs resulting from the sold property will not reduce the proceeds paid to the trust from the Underlying Properties retained by SandRidge. SandRidge will require any purchaser of any of the Underlying Properties to enter into an agreement to perform SandRidge's obligations under the administrative services agreement with respect to those properties.

Exchange, Addition and Release of Acreage. SandRidge may at its option at any time prior to the completion of its drilling obligation, cause the trust to exchange leased acreage subject to the royalty interests, free and clear of such royalty interests, for other leased acreage within the AMI and to cause such leased acreage exchanged to the trust to be made subject to the royalty interests as set forth in the conveyances. In addition, in the event SandRidge acquires any additional leases or interests in the AMI prior to the completion of its drilling obligation, SandRidge may at its option make such additional leases or interests subject to the royalty interests. In no event, however, may any exchange of acreage or any addition of leased acreage or interests be effected unless SandRidge certifies to the trust that, among other things, all of the aggregate acreage attributable to the exchanged leases or additional leases or interests shall not exceed five percent of the acreage subject to the royalty interest.

In addition, SandRidge may, at its option and without the consent of the trust unitholders, require the trust to release acreage subject to the royalty interest with an aggregate value to the trust of up to $5.0 million during any 12-month period. These releases will be made only in connection with a sale by SandRidge of a portion of the Underlying Property and are conditioned upon the trust receiving an amount equal to the fair value to the trust of such released royalty interests.

Abandonment of Underlying Property. SandRidge or any transferee of an Underlying Property will have the right to abandon any well or property if it reasonably believes the well or property ceases to produce or is not capable of producing in commercially paying quantities. In making such decisions, SandRidge or any transferee of an Underlying Property is required under the applicable conveyance to act as a reasonably prudent operator in the AMI under the same or similar circumstances would act if it were acting with respect to its own properties, disregarding the existence of the royalty interests as burdens affecting such properties. Upon termination of the lease, that portion of the royalty interests relating to the abandoned property will be extinguished.

Maintenance of Books and Records. SandRidge must maintain books and records sufficient to determine the amounts payable for the royalty interests to the trust. Quarterly and annually, SandRidge must deliver to the trustee a statement of the computation of the proceeds for each computation period as well as quarterly drilling and production results. Because SandRidge files reports with the SEC, those reports will be publicly available. See "Where You Can Find More Information."

Reservation of Rights. Pursuant to the conveyances, SandRidge will expressly except and reserve all right, title and interest in and to any well and appurtenant production facilities not expressly conveyed to the trust.

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DESCRIPTION OF THE TRUST AGREEMENT

Creation and Organization of the Trust; Amendments

The trust was created under Delaware law as a separate legal entity to acquire and hold the royalty interests for the benefit of the trust unitholders pursuant to an agreement between SandRidge, the trustee and the Delaware trustee. The royalty interests are passive in nature and neither the trust nor the trustee has any control over or responsibility for costs relating to the operation of the Underlying Properties. Neither SandRidge nor other operators of the Underlying Properties have any contractual commitments to the trust to provide additional funding or to conduct further drilling on or to maintain their ownership interest in any of these properties other than the obligations of SandRidge to designate and drill the Development Wells. After the conveyance of the royalty interests, however, SandRidge will retain an interest in each of the Underlying Properties. For a description of the Underlying Properties and other information relating to them, see "The Underlying Properties."

The trust agreement will provide that the trust's business activities will generally be limited to owning the royalty interests and entering into hedging arrangements and activities reasonably related thereto, including activities required or permitted by the terms of the conveyances related to the royalty interests. As a result, the trust will not be permitted to acquire other oil, natural gas and natural gas liquids properties or royalty interests. Additionally, following the completion of this offering, the trust will not be able to issue any additional trust units.

The beneficial interests in the trust are divided into 52,500,000 trust units. Each trust unit represents an equal undivided beneficial interest in the property of the trust. Please read "Description of the Trust Units" for additional information concerning the trust units.

Amendment of the trust agreement generally requires the vote of holders of a majority of the trust units and a majority of the common units (excluding common units owned by SandRidge and its affiliates) voting in person or by proxy at a meeting of such unitholders at which a quorum is present. At any time that SandRidge and its affiliates collectively own less than 10% of the total trust units outstanding, however, the standard for approval will be the vote of a majority of the trust units, including units owned by SandRidge, voting in person or by proxy at a meeting of the unitholders at which a quorum is present. Abstentions and broker non-votes shall not be deemed to be a vote cast. However, no amendment may:

- increase the power of the trustee to engage in business or investment activities;
- decrease the incentive threshold or increase the subordination threshold or change the portion of the quarterly cash distributions payable as an incentive distribution;
- alter the rights of the trust unitholders as among themselves; or
- permit the trustee to distribute the royalty interests in kind.

Amendments to the trust agreement's provisions addressing the following matters may not be made without SandRidge's consent:

- dispositions of the trust's assets;
- indemnification of the trustee;
- reimbursement of out-of-pocket expenses of SandRidge when acting as the trust's agent;

- termination of the trust; and

- amendments of the trust agreement.

Certain amendments to the trust agreement do not require the vote of the trust unitholders. See " Permitted Amendments."

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The business and affairs of the trust will be managed by the trustee. The trustee will have no ability to manage or influence the operations of the Underlying Properties. SandRidge operates all of the Producing Wells and expects to operate substantially all of the Development Wells during the subordination period, but will have no ability to manage or influence the management of the trust, except through its limited voting rights as a holder of trust units and its limited ability to manage the hedging program.

Assets of the Trust

Upon completion of this offering, the principal assets of the trust will consist of the PDP Royalty Interest and the Development Royalty Interest, the development agreement, the Drilling Support Lien, the administrative services agreement, the derivatives agreement, the hedge contracts with unaffiliated hedge counterparties, and any cash and temporary investments being held for the payment of expenses and liabilities and for distribution to the trust unitholders. See "The Trust" for more information.

Duties and Powers of the Trustee; Liability of the Trustee

The duties and powers of the trustee are specified in the trust agreement and by the laws of the State of Delaware, except as modified by the trust agreement. The trust agreement provides that the trustee shall not have any duties or liabilities, including fiduciary duties, except as expressly set forth in the trust agreement and the duties and liabilities of the trustee as set forth in the trust agreement replace any other duties and liabilities, including fiduciary duties, to which the trustee might otherwise be subject.

The trustee's principal duties consist of:

- collecting cash proceeds attributable to the royalty interests;
- paying expenses, charges and obligations of the trust from the trust's assets;
- receiving and making payments under the derivatives agreement with SandRidge and hedge contacts with the unaffiliated hedge counterparties;
- determining whether cash distributions exceed subordination or incentive thresholds, and making cash distributions to the unitholders and SandRidge (with respect to incentive distributions) in accordance with the trust agreement;
- causing to be prepared and distributed a Schedule K-1 for each trust unitholder and to prepare and file tax returns on behalf of the trust; and
- causing to be prepared and filed reports required to be filed under the Securities Exchange Act of 1934, as amended, and by the rules of any securities exchange or quotation system on which the trust units are listed or admitted to trading.

SandRidge will provide administrative and other services to the trust in fulfillment of certain of the foregoing duties, pursuant to the administrative services agreement.

If a trust liability is contingent or uncertain in amount or not yet currently due and payable, the trustee may create a cash reserve to pay for the liability. If the trustee determines that the cash on hand and the cash to be received are insufficient to cover the trust's liability, the trustee may cause the trust to borrow funds required to pay the liabilities. The trust may borrow the funds from any person, including the trustee or its affiliates or, as described below, SandRidge. The terms of such indebtedness, if funds were loaned by the entity serving as trustee or Delaware trustee, would be similar to the terms which such entity would grant to a similarly situated commercial customer with whom it did not have a fiduciary relationship, and such entity shall be entitled to enforce its rights with respect to any such indebtedness as if it were not then serving as trustee or Delaware trustee. If the trust borrows funds, the trust unitholders will not receive distributions until the borrowed funds are repaid (except, in certain circumstances, where the trust borrows funds from SandRidge). For information regarding SandRidge's obligation to loan funds to the trust in

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certain limited circumstances, see " SandRidge Obligation to Fund Trust Expenses in Certain Circumstances" below.

Each quarter, the trustee will pay trust obligations and expenses and distribute to the trust unitholders the remaining proceeds received from the royalty interests and hedging arrangements. The cash held by the trustee as a reserve against future liabilities must be invested in:

- interest bearing obligations of the United States government;
- money market funds that invest only in United States government securities;
- repurchase agreements secured by interest-bearing obligations of the United States government; or
- bank certificates of deposit.

Alternatively, cash held for distribution at the next distribution date may be held in a non-interest bearing account.

The trustee intends to withhold $1.0 million from the first distribution to unitholders to establish a cash reserve available to the trustee to pay trust administrative expenses. If the trustee uses such cash reserve (or any portion thereof) to pay or reimburse trust liabilities or expenses, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until the cash reserve is replenished. This cash reserve will be part of the trust estate and will bear interest at the same rate as other cash on hand in the trust estate. Upon the dissolution of the trust, the balance of the cash reserve (including accrued interest thereon) will be distributed to trust unitholders on a pro rata basis.

The trust may not acquire any asset except the royalty interests, the other assets described above under " Assets of the Trust" and cash and temporary cash investments, and it may not engage in any investment activity except investing cash on hand. The trust may also enter into replacement hedges, or modify its hedging arrangements, in certain circumstances.

The trust agreement provides that the trustee will not make business decisions affecting the assets of the trust. However, the trustee may:

- prosecute or defend, and settle, claims of or against the trust or its agents;
- retain professionals and other third parties to provide services to the trust;
- charge for its services as trustee;
- retain funds to pay for future expenses and deposit them with one or more banks or financial institutions (which may include the trustee to the extent permitted by law);
- lend funds at commercial rates to the trust to pay the trust's expenses; and
- seek reimbursement from the trust for its out-of-pocket expenses.

In discharging its duty to trust unitholders, the trustee may act in its discretion and will be liable to the trust unitholders only for willful misconduct, bad faith or gross negligence. The trustee will not be liable for any act or omission of its agents or employees unless the trustee acted with willful misconduct, bad faith or gross negligence in its selection and retention. The trustee will be indemnified individually or as the trustee for any liability or cost that it incurs in the administration of the trust, except in cases of willful misconduct, bad faith or gross negligence. The trustee will have a lien on the assets of the trust as security for this indemnification and its compensation earned as trustee. Trust unitholders will not be liable to the trustee for any indemnification. See "Description of the Trust Units Liability of Trust Unitholders." The trustee will ensure that all contractual liabilities of the trust are limited to the assets of the trust.

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Merger or Consolidation of Trust

The trust may merge or consolidate with or into, or convert into, one or more limited partnerships, general partnerships, corporations, business trusts, limited liability companies, or associations or unincorporated businesses if such transaction is agreed to by the trustee and approved by the vote of the holders of a majority of the trust units and a majority of the common units (excluding common units owned by SandRidge and its affiliates) in each case voting in person or by proxy at a meeting of such holders at which a quorum is present and such transaction is permitted under the Delaware Statutory Trust Act and any other applicable law. At any time that SandRidge and its affiliates collectively own less than 10% of the total trust units outstanding, however, the standard for approval will be the vote of a majority of the trust units, including units owned by SandRidge voting in person or by proxy at a meeting of such holders at which a quorum is present.

Trustee's Power to Sell Royalty Interests

The trustee may sell the royalty interests under any of the following circumstances:

- the sale is requested by SandRidge, following the satisfaction of its drilling obligation, in accordance with the provisions of the trust agreement; or

- the sale is approved by the vote of holders representing a majority of the trust units and a majority of the common units (excluding common units owned by SandRidge and its affiliates) in each case voting in person or by proxy at a meeting of such holders at which a quorum is present; except that at any time that SandRidge and its affiliates collectively own less than 10% of the total trust units outstanding, the standard for approval will be the vote of a majority of the trust units, including units owned by SandRidge voting in person or by proxy at a meeting of such holders at which a quorum is present.

Upon dissolution of the trust the trustee must sell the royalty interests. No trust unitholder approval is required in this event. See " Duration of the Trust; Sale of Royalty Interests" below.

The trustee will distribute the net proceeds from any sale of the royalty interests and other assets to the trust unitholders after payment or reasonable provision for payment of the liabilities of the trust.

Permitted Amendments

The trustee may amend or supplement the trust agreement, the conveyances, the development agreement, the administrative services agreement, the derivatives agreement, the hedge contracts, the registration rights agreement or the Drilling Support Lien, without the approval of the trust unitholders, to cure ambiguities, to correct or supplement defective or inconsistent provisions, to grant any benefit to all trust unitholders, to add collateral to the Drilling Support Lien, to evidence or implement any changes required by applicable law or to change the name of the trust, provided, however, that any such supplement or amendment does not adversely affect the interests of the trust unitholders. Furthermore, the trustee, acting alone, may amend the administrative services agreement without the approval of trust unitholders if such amendment would not increase the cost or expense of the trust or create an adverse economic impact on the trust unitholders. Finally, modifications of the hedging arrangements entered into by the trust will not require the approval of the trust unitholders.

All other permitted amendments to the trust agreement and other agreements listed above may only be made by the vote of a majority of the trust units and a majority of the common units (excluding common units owned by SandRidge and its affiliates) in each case voting in person or by proxy at a meeting of such holders at which a quorum is present; except that at any time that SandRidge and its affiliates collectively own less than 10% of the total trust units outstanding, the standard for approval will be the vote of a majority of the trust units, including units owned by SandRidge voting in person or by proxy at a meeting of such holders at which a quorum is present. Abstentions and broker non-votes shall not be deemed to be a vote cast.

Liabilities of the Trust; Fees and Expenses

The trust will be a party to oil and natural gas hedging arrangements and could have payment obligations under such arrangements. Otherwise, the trust does not conduct an active business and the trustee has little power to incur obligations. As a result, it is expected that the trust will only incur liabilities for routine administrative expenses, such as legal, accounting, tax advisory, engineering, printing and other administrative and out-of-pocket fees and expenses incurred by or at the direction of the trustee or the Delaware trustee, including tax return and Schedule K-1 preparation and mailing costs; independent auditor fees; and registrar and transfer agent fees. The trust will also be responsible for paying costs associated with annual and quarterly reports to unitholders. Moreover, the trustee's and the Delaware trustee's compensation, and the fee payable to SandRidge pursuant to the administrative services agreement will be paid out of the trust's assets. See "The Trust" for more information on these costs.

SandRidge Obligation to Fund Trust Expenses in Certain Circumstances

SandRidge has agreed that, if at any time the trust's cash on hand (including available cash reserves) is not sufficient to pay the trust's ordinary course administrative expenses as they become due, SandRidge will loan funds to the trust necessary to pay such expenses. Any funds loaned by SandRidge pursuant to this commitment will be limited to the payment of current accounts payable or other obligations to trade creditors in connection with obtaining goods or services or the payment of other accrued current liabilities arising in the ordinary course of the trust's business, and may not be used to satisfy trust indebtedness. If SandRidge loans funds pursuant to this commitment, unless SandRidge agrees otherwise, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid. Any such loan will be on an unsecured basis, and the terms of such loan will be substantially the same as those which would be obtained in an arms' length transaction between SandRidge and an unaffiliated third party.

Duration of the Trust; Sale of Royalty Interests

The trust will not dissolve until the Termination Date, which is March 31, 2031, unless:

- the trust sells all of the royalty interests;
- cash available for distribution for any four consecutive quarters, on a cumulative basis, is less than $5.0 million;
- the holders of a majority of the total trust units outstanding and a majority of the common units (excluding common units owned by SandRidge and its affiliates) in each case voting in person or by proxy at a meeting of such holders at which a quorum is present vote in favor of dissolution; except that at any time that SandRidge and its affiliates collectively own less than 10% of the total trust units outstanding, the standard for approval will be a majority of the trust units, including units owned by SandRidge voting in person or by proxy at a meeting of such holders at which a quorum is present; or
- the trust is judicially dissolved.

In the case of any of the foregoing, the trustee would sell all of the trust's assets, either by private sale or public auction, and distribute the net proceeds of the sale to the trust unitholders after payment, or reasonable provision for payment, of all trust liabilities.

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Dispute Resolution

To the fullest extent permitted by law, any dispute, controversy or claim that may arise between SandRidge and the trustee relating to the trust will be submitted to binding arbitration before a panel of three arbitrators.

Tax Matters

Trust unitholders will be treated as partners of the trust for U.S. federal income tax purposes. The trust agreement contains tax provisions that generally allocate the trust's income, gain, loss, deduction and credit among the trust unitholders in accordance with their percentage interests in the trust. The trust agreement also sets forth the tax accounting principles to be applied by the trust.

Miscellaneous

The trustee may consult with counsel (which may include counsel to SandRidge), accountants, tax advisors, geologists and engineers and other parties the trustee believes to be qualified as experts on the matters for which advice is sought. The trustee will be protected for any action it takes in good faith reliance upon the opinion of the expert.

The Delaware trustee and the trustee may resign at any time or be removed with or without cause at any time by the vote of a majority of the common units (excluding common units owned by SandRidge and its affiliates) voting in person or by proxy at a meeting of such holders at which a quorum is present; except that at any time that SandRidge and its affiliates collectively own less than 10% of the total trust units outstanding, the standard for approval will be the vote of a majority of the trust units, including units owned by SandRidge, voting in person or by proxy at a meeting of such holders at which a quorum is present. Abstentions and broker non-votes shall not be deemed to be a vote cast. Any successor must be a bank or trust company meeting certain requirements including having combined capital, surplus and undivided profits of at least $20 million, in the case of the Delaware trustee, and $100 million, in the case of the trustee.

The principal offices of the trust are located at 919 Congress Avenue, Suite 500, Austin, Texas 78701, and its telephone number is (512) 236-6599.

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DESCRIPTION OF THE TRUST UNITS

Each trust unit is a unit of the beneficial interest in the trust and is entitled to receive cash distributions from the trust on a pro rata basis. Each trust unitholder has the same rights regarding each of his trust units as every other trust unitholder has regarding his units. The trust will have 52,500,000 trust units outstanding upon completion of the offering, consisting of 39,375,000 common units and 13,125,000 subordinated units.

Common Units; Subordinated Units

The trust units will initially be comprised of both common units and subordinated units. The common units and subordinated units will have identical rights and privileges, except with respect to their voting rights and rights to receive distributions. For a discussion of unitholders' voting rights, see " Voting Rights of Trust Unitholders" below.

The subordinated units will be entitled to receive pro rata distributions from the 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 of the common units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on all the common units, including the common units held by SandRidge. For more information, see "Target Distributions and Subordination and Incentive Thresholds."

The subordinated units will automatically convert into common units on a one-for-one basis at the end of the fourth full calendar quarter following SandRidge's satisfaction of its drilling obligation to the trust with respect to the Development Wells.

Distributions; Income Computations

Cash distributions to trust unitholders will be made by the trust from its available funds for each calendar quarter. Royalty interest payments due to the trust with respect to any calendar quarter will be based on actual production volumes attributable to the trust properties for the first two months of the quarter just ended as well as the last month of the immediately preceding quarter (as measured at SandRidge metering systems) and actual revenues received for such volumes. During the term of the derivatives agreement, SandRidge will determine the amounts due to (or from) the trust under the derivatives agreement. SandRidge will make a payment to the trust equal to the sum of the royalty interest payments and amounts due the trust under the derivatives agreement within 45 days of the end of each calendar quarter. In addition, any payment due from or required to be made to the counterparties under the trust's direct hedge contracts or SandRidge under the derivatives agreement will be paid by the 45th day following the end of such calendar quarter. After the receipt and disbursement of all such amounts, the trustee will determine for such calendar quarter the amount of funds available for distribution to the trust unitholders. Available funds are the excess cash, if any, received by the trust over the trust's expenses for that quarter. Available funds will be reduced by any cash the trustee decides to hold as a reserve against future liabilities.

The amount of available funds for distribution each quarter will be payable to the trust unitholders of record on or about the 45th day following the end of such calendar quarter or such later date as the trustee determines is required to comply with legal or stock exchange requirements. The trustee will distribute cash on or about the 60th day (or the next succeeding business day following such day if such day is not a business day) following such calendar quarter to each person who was a trust unitholder of record on the quarterly record date, together with interest expected to be earned on the amount of such quarterly distribution from the date of receipt thereof by the trustee to the payment date.

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Unless otherwise advised by counsel or the IRS, the trustee will treat the income and expenses of the trust for each quarter as belonging to the trust unitholders of record on the quarterly record date that occurs in such quarter. Trust unitholders will recognize income and expenses for tax purposes in the quarter the trust receives or pays those amounts, rather than in the quarter the trust distributes them. Minor variances may occur. For example, the trustee could establish a reserve in one quarter that would not result in a tax deduction until a later quarter. The trustee could also make a payment in one month that would be amortized for tax purposes over several quarters. See "U.S. Federal Income Tax Considerations."

Transfer of Trust Units

Trust unitholders may transfer their trust units in accordance with the trust agreement. The trustee will not require either the transferor or transferee to pay a service charge for any transfer of a trust unit. The trustee may require payment of any tax or other governmental charge imposed for a transfer. The trustee may treat the owner of any trust unit as shown by its records as the owner of the trust unit. The trustee will not be considered to know about any claim or demand on a trust unit by any party except the record owner. A person who acquires a trust unit after any quarterly record date will not be entitled to the distribution relating to that quarterly record date. Delaware law will govern all matters affecting the title, ownership or transfer of trust units.

Tax Schedules and Periodic Reports

The trustee will file all required trust federal and state income tax and information returns. The trustee will prepare and mail to trust unitholders a Schedule K-1 that trust unitholders need to correctly report their share of the income and deductions of the trust. The trustee will also cause to be prepared and filed reports required to be filed under the Securities Exchange Act of 1934, as amended, and by the rules of any securities exchange or quotation system on which the trust units are listed or admitted to trading.

Each trust unitholder and his representatives may examine, for any proper purpose, during reasonable business hours the records of the trust and the trustee.

Liability of Trust Unitholders

Under the Delaware Statutory Trust Act, trust unitholders will be entitled to the same limitation of personal liability extended to stockholders of private corporations for profit under the General Corporation Law of the State of Delaware. No assurance can be given, however, that the courts in jurisdictions outside of Delaware will give effect to such limitation.

Voting Rights of Trust Unitholders

The trustee or trust unitholders owning at least 10% of the total trust units outstanding may call meetings of trust unitholders. The trust will be responsible for all costs associated with calling a meeting of trust unitholders unless such meeting is called by the trust unitholders, in which case the trust unitholders will be responsible for all costs associated with calling such meeting of trust unitholders. Meetings must be held in such location as is designated by the trustee in the notice of such meeting. The trustee must send notice of the time and place of the meeting and the matters to be acted upon to all of the trust unitholders at least 20 days and not more than 60 days before the meeting. Trust unitholders representing a majority of trust units outstanding must be present or represented to have a quorum. Each trust unitholder is entitled to one vote for each trust unit owned. Abstentions and broker non-votes shall not be deemed to be a vote cast.

Unless otherwise required by the trust agreement, a matter may be approved or disapproved by the vote of a majority of the trust units held by the trust unitholders voting in person or by proxy at a meeting

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where there is a quorum. This is true, even if a majority of the total trust units outstanding did not approve it.

Until such time as SandRidge and its affiliates own less than 10% of the total trust units outstanding, the vote of the holders of a majority of common units (excluding common units owned by SandRidge and its Affiliates) and a majority of trust units voting in person or by proxy at a meeting of such holders at which a quorum is present is required to:

- dissolve the trust (except in accordance with its terms);
- amend the trust agreement, the royalty conveyances, the administrative services agreement, the development agreement, the Drilling Support Lien or the derivatives agreement (except with respect to certain matters that do not adversely affect the right of trust unitholders in any material respect);
- merge or consolidate or convert the trust with or into another entity; or
- approve the sale of all or any material part of the assets of the trust.

In addition, until such time as SandRidge and its affiliates own less than 10% of the total trust units outstanding, the vote of the holders of a majority of common units (excluding common units owned by SandRidge and its affiliates) voting in person or by proxy at a meeting of such holders at which a quorum is present is required to remove the trustee and to appoint a successor trustee.

At any time when SandRidge and its affiliates own less than 10% of the total trust units outstanding, the vote of the holders of a majority of trust units, including units owned by SandRidge voting in person or by proxy at a meeting of such holders at which a quorum is present will be required to take the actions described above.

Certain amendments to the trust agreement may be made by the trustee without approval of the trust unitholders. The trustee must consent before all or any part of the trust assets can be sold except in connection with the dissolution of the trust or limited sales directed by SandRidge in conjunction with its sale of Underlying Properties.

Comparison of Trust Units and Common Stock

Trust unitholders have more limited voting rights than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of trust unitholders or for annual or other periodic re-election of the trustee.

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Unitholders should also be aware of the following ways in which an investment in trust units is different from an investment in common stock of a corporation.

	Trust units	Common stock
Voting	The trust agreement provides voting rights to trust unitholders to remove and replace (but not elect) the trustee and to approve or disapprove major trust transactions.	Unless otherwise provided in the certificate of incorporation, corporate statutes provide voting rights to stockholders of the corporation to elect directors and to approve or disapprove amendments to the certificate of incorporation and certain major corporate transactions.
Income Tax	The trust is not subject to U.S. federal income tax, although it will be subject to Texas franchise tax. Trust unitholders are subject to income tax on their allocable share of trust income, gain, loss and deduction.	Corporations are subject to U.S. federal income tax and Texas franchise tax. Their stockholders are taxed on dividends.
Distributions	All trust revenue is distributed to trust unitholders after payment of trust expenses and additions, if any, to trust reserves.	Unless otherwise provided in the certificate of incorporation, stockholders are entitled to receive dividends solely at the discretion of the board of directors.
Business and Assets	The business of the trust is limited to specific assets with a finite economic life.	Unless otherwise provided in the certificate of incorporation, a corporation conducts an active business for an unlimited term and can reinvest its earnings and raise additional capital to expand.
Fiduciary Duties	To the extent provided in the trust agreement, the trustee has limited its fiduciary duties in the trust agreement as permitted by the Delaware Statutory Trust Act so that it will be liable to unitholders only for willful misconduct, bad faith or gross negligence.	Officers and directors have a fiduciary duty of loyalty to the corporation and the stockholders and a duty to exercise due care in the management and administration of a corporation's affairs.

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TRUST UNITS ELIGIBLE FOR FUTURE SALE

General

Prior to this offering, there has been no public market for the common units. Sales of substantial amounts of the common units in the open market, or the perception that those sales could occur, could adversely affect prevailing market prices.

Upon completion of this offering, there will be 52,500,000 trust units outstanding. All of the 30,000,000 common units sold in this offering, or the 34,500,000 common units if the underwriters exercise their over-allotment option in full, will be freely tradable without restriction under the Securities Act. All of the 22,500,000 trust units to be held by SandRidge (18,000,000 trust units if the underwriters exercise their over-allotment in full) following completion of the offering will be "restricted securities" within the meaning of Rule 144 under the Securities Act and may not be sold other than through registration under the Securities Act or pursuant to an exemption from registration, subject to the restrictions on transfer contained in the lock-up agreements described below and in "Underwriters." SandRidge expects to pledge all of the units it owns after completion of the offering as collateral under its credit facility.

SandRidge Lock-up Agreement

In connection with this offering, SandRidge has agreed, for a period of 180 days after the date of this prospectus, not to offer, sell, contract to sell or otherwise dispose of or transfer any trust units or any securities convertible into or exchangeable for trust units, without the prior written consent of Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC and Wells Fargo Securities, LLC, the representatives of the underwriters. See "Underwriters" for a description of this lock-up agreement. Upon the expiration of this lock-up agreement, all of the units held by SandRidge will be eligible for sale in the public market under Rule 144 of the Securities Act, subject to volume limitations and other restrictions contained in Rule 144, or through registration under the Securities Act.

Rule 144

The common units sold in the offering will generally be freely transferable without restriction or further registration under the Securities Act, except that any common units owned by an "affiliate" of SandRidge or the trust may not be resold publicly except in compliance with the registration requirements of the Securities Act or under an exemption under Rule 144 or otherwise. Rule 144 permits securities acquired by an affiliate to be sold into the market in an amount that does not exceed, during any three-month period, the greater of:

- 1.0% of the total number of the securities outstanding, or
- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

Sales under Rule 144 are also subject to specific manner of sale provisions, holding period requirements, notice requirements and the availability of current public information about the trust. A person who is not deemed to have been an affiliate of SandRidge or the trust at any time during the three months preceding a sale, and who has beneficially owned common units for at least six months (provided the trust is in compliance with the current public information requirement) or one year (regardless of whether the trust is in compliance with the current public information requirement), would be entitled to sell common units under Rule 144 without regard to the rule's public information requirements, volume limitations, manner of sale provisions and notice requirements.

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Registration Rights Agreement

The trust intends to enter into a registration rights agreement for the benefit of SandRidge and certain of its affiliates and transferees (each, a "holder"). In the registration rights agreement, the trust will agree, for the benefit of each holder, to register the trust units held by such holder. Specifically, the trust will agree:

- subject to the restrictions described above under " SandRidge Lock-up Agreement" and under "Underwriters Lock-up Agreement," to use its reasonable best efforts to file a registration statement, including, if so requested, a shelf registration statement, with the SEC as promptly as practicable following receipt of a notice requesting the filing of a registration statement from holders representing a majority of the then outstanding registrable trust units;

- to use its reasonable best efforts to cause the registration statement or shelf registration statement to be declared effective under the Securities Act as promptly as practicable after the filing thereof; and

- to continuously maintain the effectiveness of the registration statement under the Securities Act for 90 days (or continuously if a shelf registration statement is requested) after the effectiveness thereof or until the trust units covered by the registration statement have been sold pursuant to such registration statement or until all registrable trust units:

  - have been sold pursuant to Rule 144 under the Securities Act if the transferee thereof does not receive "restricted securities;"

  - have been sold in a private transaction in which the transferor's rights under the registration rights agreement are not assigned to the transferee of the trust units; or

  - become eligible for resale pursuant to Rule 144 (or any similar rule then in effect under the Securities Act).

The holders will have the right to require the trust to file no more than five registration statements in aggregate.

In connection with the preparation and filing of any registration statement, SandRidge will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the trust, which will be borne by the trustee, and any underwriting discounts and commissions, which will be borne by the seller of the trust units.

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U.S. FEDERAL INCOME TAX CONSIDERATIONS

This section is a discussion of the material tax considerations that may be relevant to prospective trust unitholders who are individual citizens or residents of the United States and, unless otherwise noted in the following discussion, is the opinion of Covington & Burling LLP, counsel to SandRidge and the trust, insofar as it relates to legal conclusions with respect to matters of U.S. federal income tax law. This section is based upon current provisions of the Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"), existing and proposed Treasury regulations promulgated under the Internal Revenue Code (the "Treasury Regulations") and current administrative rulings and court decisions, all of which are subject to change. Future changes in these authorities may cause the tax consequences to vary substantially from the consequences described below.

The following discussion does not address all U.S. federal income tax matters affecting the trust or the trust unitholders. Moreover, the discussion focuses on trust unitholders who are individual citizens or residents of the United States and has only limited application to corporations, estates, trusts, nonresident aliens or other unitholders subject to specialized tax treatment, such as tax-exempt institutions, non-U.S. persons, taxpayers subject to the alternative minimum tax, individual retirement accounts (IRAs), employee benefit plans, real estate investment trusts (REITs) or mutual funds. Accordingly, the trust encourages each prospective trust unitholder to consult, and depend on, his own tax advisor in analyzing the federal, state, local and foreign tax consequences particular to him of the ownership or disposition of trust units.

No ruling has been or will be requested from the Internal Revenue Service (the "IRS") regarding any matter affecting the trust or prospective trust unitholders. Instead, the trust will rely on opinions of counsel. Unlike a ruling, an opinion of counsel represents only that counsel's best legal judgment and does not bind the IRS or the courts. Accordingly, the opinions and statements made herein may not be sustained by a court if contested by the IRS. Any contest of this sort with the IRS may materially and adversely impact the market for the trust units and the prices at which trust units trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will result in a reduction in cash available for distribution to the trust unitholders, and thus will be borne indirectly by the trust unitholders. Furthermore, the tax treatment of the trust, or of an investment in the trust, may be significantly modified by future legislative or administrative changes or court decisions. Any modifications may or may not be retroactively applied.

All statements as to matters of law and legal conclusions, but not as to factual matters, contained in this section, unless otherwise noted, are the opinion of Covington & Burling LLP and are based on the accuracy of the representations made by SandRidge and the trust.

For the reasons described below, Covington & Burling LLP has not rendered an opinion with respect to the following specific U.S. federal income tax issues: (1) the treatment of a trust unitholder whose trust units are loaned to a short seller to cover a short sale of trust units (please read " Tax Consequences of Trust Unit Ownership Treatment of Short Sales"); (2) whether the trust's convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read " Disposition of Trust Units Allocations Between Transferors and Transferees"); and (3) whether percentage depletion will be available to a trust unitholder or the extent of the percentage depletion deduction available to any trust unitholder (please read " Tax Consequences of Trust Unit Ownership Tax Treatment of the Perpetual Royalties").

As used herein, the term "trust unitholder" means a beneficial owner of trust units that for U.S. federal income tax purposes is:

- an individual who is a citizen of the United States or who is resident in the United States for U.S. federal income tax purposes,
- a corporation, or an entity treated as a corporation for U.S. federal income tax purposes, created or organized in or under the laws of the United States, a state thereof or the District of Columbia,

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- an estate the income of which is subject to U.S. federal income taxation regardless of its source, or

- a trust if it is subject to the primary supervision of a U.S. court and the control of one or more United States persons (as defined for U.S. federal income tax purposes) or that has a valid election in effect under applicable U.S. Treasury regulations to be treated as a United States person.

The term "non-U.S. trust unitholder" means any beneficial owner of a trust unit (other than an entity that is classified for U.S. federal income tax purposes as a partnership or as a "disregarded entity") that is not a trust unitholder.

If an entity that is classified for U.S. federal income tax purposes as a partnership is a beneficial owner of trust units, the tax treatment of a member of the entity will depend upon the status of the member and the activities of the entity. The trust encourages any entity that is classified for U.S. federal income tax purposes as a partnership and that is a beneficial owner of trust units, and the members of such an entity, to consult their own tax advisors about the U.S. federal income tax considerations of purchasing, owning, and disposing of trust units.

Classification of the Trust as a Partnership

Although the trust is formed as a statutory trust under Delaware law, the trust's classification for U.S. federal income tax purposes is based on its characteristics rather than its form. Based on such characteristics, it is expected that, as described below, the trust will be treated for federal and applicable state income tax purposes as a partnership and trust unitholders will be treated as partners in that partnership.

A partnership is not a taxable entity and incurs no U.S. federal income tax liability. Instead, each partner of a partnership is required to take into account his share of items of income, gain, loss, deduction and credit of the partnership in computing his federal income tax liability, regardless of whether cash distributions are made to him by the partnership. Distributions by a partnership to a partner are generally not taxable to the partner unless the amount of cash distributed to him is in excess of the partner's adjusted basis in his partnership interest as of the end of the taxable year in which the distribution is made.

Section 7704 of the Internal Revenue Code provides that publicly traded partnerships will, as a general rule, be taxed as corporations. However, an exception, referred to in this discussion as the "Qualifying Income Exception," exists with respect to publicly traded partnerships of which 90% or more of the gross income for every taxable year consists of "qualifying income." Qualifying income includes income and gains derived from the exploration, development, production and marketing of oil, natural gas and natural gas liquids and interest income (other than from a financial business). Other types of qualifying income include gains from the sale of real property and income from certain hedging transactions. The trust anticipates that substantially all of its gross income will be qualifying income. Based upon the factual representations made by the trust and SandRidge and a review of the applicable legal authorities, Covington & Burling LLP is of the opinion that at least 90% of the trust's gross income will constitute qualifying income.

No ruling has been or will be sought from the IRS and the IRS has made no determination as to the trust's status for federal income tax purposes or whether the trust's operations generate "qualifying income" under Section 7704 of the Internal Revenue Code. Instead, the trust will rely on the opinion of Covington & Burling LLP on such matters. It is the opinion of Covington & Burling LLP that, based upon the Internal Revenue Code, Treasury Regulations, published revenue rulings and court decisions and the representations described below, the trust will be classified as a partnership for federal income tax purposes.

In rendering its opinion, Covington & Burling LLP has relied on factual representations made by the trust and SandRidge. The representations made by the trust and SandRidge upon which Covington & Burling LLP has relied are:

(a) The trust has not, and will not, elect to be treated as a corporation;

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(b) The trust is, and will be organized and operated in accordance with (1) all applicable trust statutes, including the Delaware Statutory Trust Act, (2) the trust agreement, and (3) the description thereof in this prospectus;

(c) For each taxable year, more than 90% of the trust's gross income will be income that Covington & Burling LLP has opined or will opine is qualifying income within the meaning of Section 7704(d) of the Internal Revenue Code; and

(d) Each hedging transaction that the trust treats as resulting in qualifying income will be appropriately identified as a hedging transaction pursuant to applicable Treasury Regulations, and will be associated with oil, gas or products thereof that are held or will be held by the trust in activities that Covington & Burling LLP has opined or will opine result in qualifying income.

The trust believes that these representations are true and expects that these representations will continue to be true in the future.

If the trust fails to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery (in which case the IRS may also require the trust to make adjustments with respect to the trust's unitholders allocable share of trust income, gain, loss or deduction or pay other amounts), the trust will be treated as if it had transferred all of its assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which the trust fails to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in the trust. This deemed contribution and liquidation should be tax-free to the trust unitholders and the trust. Thereafter, the trust would be treated as an association taxable as a corporation for federal income tax purposes.

If the trust were treated as an association taxable as a corporation in any taxable year, either as a result of a failure to meet the Qualifying Income Exception or otherwise, the trust's items of income, gain, loss and deduction would be reflected only on the trust's tax return rather than being passed through to the trust unitholders, and the trust's net income would be taxed to the trust at corporate rates. In addition, any distribution made to a trust unitholder would be treated as either taxable dividend income, to the extent of the trust's current or accumulated earnings and profits, or, in the absence of earnings and profits, a nontaxable return of capital, to the extent of the trust unitholder's tax basis in his trust units, or taxable capital gain, after the trust unitholder's tax basis in his trust units is reduced to zero. Accordingly, taxation as a corporation would result in a material reduction in a trust unitholder's cash flow and after-tax return and thus would likely result in a substantial reduction of the value of the trust units.

The discussion below is based on Covington & Burling LLP's opinion that the trust will be classified as a partnership for U.S. federal income tax purposes.

Partner Status

Trust unitholders will be treated as partners of the trust for U.S. federal income tax purposes. Also, trust unitholders whose trust units are held in street name or by a nominee and who have the right to direct the nominee in the exercise of all substantive rights attendant to the ownership of their trust units will be treated as partners of the trust for U.S. federal income tax purposes.

A beneficial owner of trust units whose trust units have been transferred to a short seller to complete a short sale would appear, as a result, to lose his status as a partner with respect to those trust units for U.S. federal income tax purposes. Please read " Tax Consequences of Trust Unit Ownership Treatment of Short Sales." Income, gain, deductions or losses would not appear to be reportable by a trust unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a trust unitholder who is not a partner for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These unitholders are urged to consult their own tax advisors with respect to their tax considerations related to holding trust units. The references to "unitholders" in the discussion that follows are to persons who are treated as partners in the trust for federal income tax purposes.

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Tax Classification of the PDP Royalty Interest and the Development Royalty Interest

For U.S. federal income tax purposes, the Perpetual PDP Royalty and the Perpetual Development Royalty will have the tax characteristics of mineral royalty interests to the extent they are, at the time of their creation, reasonably expected to have an economic life that corresponds substantially to the economic life of the mineral property or properties burdened thereby. Payments out of production that are received in respect of a mineral interest that constitutes a royalty interest for U.S. federal income tax purposes are taxable under current law as ordinary income subject to an allowance for cost or percentage depletion in respect of such income.

In contrast, the Term PDP Royalty and the Term Development Royalty will have the tax characteristics of production payments governed by Section 636 of the Internal Revenue Code to the extent they may not, at the time of their creation, be reasonably expected to extend in substantial amounts over the entire productive lives of the mineral property or properties they burden. Payments out of production that are received in respect of a mineral interest that constitutes a production payment for U.S. federal income tax purposes are treated under current law as consisting of a receipt of principal and interest on a nonrecourse debt obligation, with the interest component being taxable as ordinary income.

In the event that a portion of a single royalty interest terminates by its terms prior to the point in time that the economically productive life of the burdened mineral property is substantially exhausted and the remaining portion continues to burden the property until its economically productive life is substantially exhausted, the federal income tax characteristics of the royalty interest are determined as if it comprised two separate interests, with the terminating portion being treated as a production payment and the continuing portion being treated as a royalty interest.

Based on the reserve report and representations made by SandRidge regarding the expected economic life of the Underlying Properties and the expected duration of the Term Royalties and the Perpetual Royalties, the Term PDP Royalty will and the Term Development Royalty should be treated as "production payments" under Section 636 of the Internal Revenue Code, and thus as nonrecourse debt instruments of SandRidge for U.S. federal income tax purposes. The Perpetual PDP Royalty will and the Perpetual Development Royalty should be treated as continuing, nonoperating economic interests in the nature of royalties payable out of production from the mineral interests they burden.

The difference in certainty between the treatment of the Term PDP Royalty and the Perpetual PDP Royalty, on the one hand, and the Term Development Royalty and the Perpetual Development Royalty, on the other hand, stems from the fact that while the Term PDP Royalty and Perpetual PDP Royalty are interests in the Producing Wells (developed wells that have been drilled), the Term Development Royalty and Perpetual Development Royalty are interests in the Development Wells (undeveloped wells that will be drilled in the future). The applicable laws are well developed, and directly applicable precedents exist, with regard to the tax treatment of royalty interests in specified developed wells that have been drilled. Although such laws and precedents are applicable in analyzing the tax treatment of royalty interests in proven reserves and undeveloped wells related thereto that will be drilled in the future, the law is less well developed in this area. As a result, the tax treatment of the Term Development Royalty and the Perpetual Development Royalty are not entirely free from doubt. Therefore, the difference in certainty between the treatment of the PDP Royalties and the Development Royalties set forth in the preceding paragraph and elsewhere in this prospectus reflects the difference in certainty between developed and undeveloped wells.

Consistent with the foregoing, SandRidge and the trust intend to treat the Perpetual Royalties as mineral royalty interests for U.S. federal income tax purposes. In addition, SandRidge and the trust intend to treat the Term Royalties as debt instruments for U.S. federal income tax purposes subject to the Treasury Regulations applicable to contingent payment debt instruments (the "CPDI regulations"), and the trust will agree to be bound by SandRidge's application of the CPDI regulations, including SandRidge's determination of the rate at which interest will be deemed to accrue on such interests. The remainder of this discussion assumes that the Term Royalties will be treated in accordance with that agreement and SandRidge's determinations and that the Perpetual Royalties will be treated as mineral

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royalty interests. No assurance can be given that the IRS will not assert that such interests should be treated differently. Such different treatment could affect the amount, timing and character of income, gain or loss in respect of an investment in trust units and could require a trust unitholder to accrue interest income at a rate different than the "comparable yield" described below. Please read " Tax Consequences of Trust Unit Ownership Tax Treatment of the Term Royalties," and " Tax Consequences of Trust Unit Ownership Tax Treatment of the Perpetual Royalties."

Tax Consequences of Trust Unit Ownership

Flow-Through of Taxable Income. As a partnership for U.S. federal income tax purposes, the trust will not be a taxable entity required to pay any federal income tax. Instead, each trust unitholder will be required to report on his income tax return his allocable share of the trust's income, gains, losses, deductions and credits without regard to whether the trust makes cash distributions to him. Consequently, the trust may allocate taxable income to a trust unitholder even if he has not received a cash distribution.

Accounting Method and Taxable Year. The trust will use the year ending December 31 as its taxable year and the accrual method of accounting for U.S. federal income tax purposes. Each trust unitholder will be required to include in income his share of the trust's income, gain, loss, deduction and credit for the trust's taxable year ending within or with his taxable year. In addition, a trust unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his trust units following the close of the trust's taxable year but before the close of his taxable year must include his share of the trust's income, gain, loss, deduction and credit in his taxable income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than 12 months of the trust's income, gain, loss, deduction and credit. Please read " Disposition of Trust Units Allocations Between Transferors and Transferees."

A trust unitholder's initial tax basis for his trust units will be the amount he paid for the trust units. That basis will be increased by his share of the trust's income and gain and decreased, but not below zero, by distributions from the trust, by the trust unitholder's share of the trust's losses, if any, by depletion deductions taken by him to the extent such deductions do not exceed his proportionate allocated share of the adjusted tax basis of the Perpetual Royalties, and by his share of the trust's expenditures that are not deductible in computing taxable income and are not required to be capitalized. Please read " Disposition of Trust Units Recognition of Gain or Loss."

Allocation of Income, Gain, Loss, Deduction and Credit. In general, if the trust has a net profit, the trust's items of income, gain, loss, deduction and credit will be allocated among the trust unitholders in accordance with their percentage interests in the trust. At any time that distributions are made to the common units in excess of distributions to the subordinated trust units, or Sandridge receives incentive distributions, gross income will be allocated to the recipients to the extent of these distributions. If the trust has a net loss, that loss will be allocated first to the subordinated trust units to the extent of their positive capital accounts and thereafter to the trust unitholders in accordance with their percentage interests in the trust.

Specified items of the trust's income, gain, loss, deduction and credit will be allocated under Section 704(c) of the Internal Revenue Code to account for any difference between the tax basis and fair market value of any property treated as having been contributed to the trust by SandRidge or certain of its affiliates that exists at the time of such contribution, together, referred to in this discussion as the "Contributed Property." These "Section 704(c) Allocations" are required to eliminate the difference between a partner's "book" capital account, credited with the fair market value of Contributed Property, and the "tax" capital account, credited with the tax basis of Contributed Property, referred to in this discussion as the "Book-Tax Disparity." The effect of these Section 704(c) Allocations to a unitholder purchasing trust units from the trust in this offering will be essentially the same as if the tax bases of the trust's assets were equal to their fair market value at the time of this offering. Finally, although the trust does not expect that its operations will result in the creation of negative capital accounts, if negative capital accounts nevertheless result, items of the trust's income and gain will be allocated in an amount and manner sufficient to eliminate the negative balance as quickly as possible.

An allocation of items of the trust's income, gain, loss, deduction or credit, other than an allocation required by Section 704(c) of the Internal Revenue Code to eliminate the Book-Tax Disparity, will generally be given effect for U.S. federal income tax purposes in determining a unitholder's share of an item of income, gain, loss, deduction or credit only if the allocation has substantial economic effect. In any other case, a unitholder's share of an item will be determined on the basis of his interest in the trust, which will be determined by taking into account all the facts and circumstances, including:

- his relative contributions to the trust;
- the interests of all the unitholders in profits and losses;
- the interest of all the unitholders in cash flow; and
- the rights of all the unitholders to distributions of capital upon liquidation.

Covington & Burling LLP is of the opinion that, with the exception of the issues described in "Disposition of Trust Units Allocations Between Transferors and Transferees," allocations under the trust agreement will be given effect for U.S. federal income tax purposes in determining a unitholder's share of an item of income, gain, loss, deduction or credit.

Treatment of Trust Distributions. Distributions by the trust to a trust unitholder generally will not be taxable to the trust unitholder for U.S. federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his trust units immediately before the distribution. The trust's cash distributions in excess of a unitholder's tax basis (if any) generally will be considered to be gain from the sale or exchange of the trust units, taxable in accordance with the rules described under " Disposition of Trust Units" below.

Ratio of Taxable Income to Distributions. The trust estimates that a purchaser of trust units in this offering who owns those trust units from the date of closing of this offering through the record date for distributions for the period ending December 31, 2013, will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be approximately 60% of the cash distributed with respect to that period. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond the trust's control. Further, the estimates are based on current tax law and tax reporting positions that the trust will adopt and with which the IRS could disagree. Accordingly, the trust cannot assure unitholders that these estimates will prove to be correct. The actual percentage of distributions that will correspond to taxable income could be higher or lower than expected, and any differences could be material and could materially affect the value of the trust units.

Tax Treatment of the Term Royalties. Under the CPDI regulations, the trust generally will be required to accrue income on the Term Royalties which are treated as production payments, and therefore as nonrecourse debt obligations of SandRidge for U.S. federal income tax purposes, in the amounts described below.

The CPDI regulations provide that the trust must accrue an amount of ordinary interest income for U.S. federal income tax purposes, for each accrual period prior to and including the maturity date of the debt instrument that equals:

- the product of (1) the adjusted issue price (as defined below) of the debt instrument as of the beginning of the accrual period; and (2) the comparable yield to maturity (as defined below) of such debt instrument, adjusted for the length of the accrual period;
- divided by the number of days in the accrual period; and

multiplied by the number of days during the accrual period that the trust held the debt instrument.

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The "issue price" of the debt instrument represented by each production payment held by the trust is the portion of the first price at which a substantial amount of the trust units is sold to the public, excluding sales to bond houses, brokers or similar persons or organizations acting in the capacity of underwriters, placement agents or wholesalers, that is allocable to the production payment based on the relative fair market value of the production payment to the other assets of the trust. The "adjusted issue price" of such a debt instrument is its issue price increased by any interest income previously accrued, determined without regard to any adjustments to interest accruals described below, and decreased by the projected amount of any payments scheduled to be made with respect to the debt instrument at an earlier time (without regard to the actual amount paid). The term "comparable yield" means the annual yield SandRidge would be expected to pay, as of the initial issue date, on a fixed rate debt security with no contingent payments but with terms and conditions otherwise comparable to those of the debt instrument represented by the production payment.

SandRidge will determine the comparable yield and provide this information to the trust. In addition, the CPDI regulations require that SandRidge provide to the trust, solely for determining the amount of interest accruals for U.S. federal income tax purposes, a schedule of the projected amounts of payments, which are referred to as projected payments, on the Term Royalties treated as debt instruments held by the trust. These payments set forth on the schedule must produce a total return on such debt instruments equal to their comparable yield. Amounts treated as interest under the CPDI regulations are treated as original issue discount for all purposes of the Internal Revenue Code.

As required by the CPDI regulations, for U.S. federal income tax purposes, the trust must use the comparable yield and the schedule of projected payments as described above in determining the trust's interest accruals, and the adjustments thereto described below, in respect of the debt instruments held by the trust.

SandRidge's determinations of the comparable yield and the projected payment schedule are not binding on the IRS and it could challenge such determinations. If it did so, and if any such challenge were successful, then the amount and timing of interest income accruals of the trust would be different from those reported by the trust or included on previously filed tax returns by the trust unitholders.

The comparable yield and the schedule of projected payments are not determined for any purpose other than for the determination for U.S. federal income tax purposes of the trust's interest accruals and adjustments thereof in respect of the debt instruments held by the trust and do not constitute a projection or representation regarding the actual amounts payable to the trust.

For U.S. federal income tax purposes, the trust is required under the CPDI regulations to use the comparable yield and the projected payment schedule established by SandRidge in determining interest accruals and adjustments in respect of the production payments, unless the trust timely discloses and justifies the use of a different comparable yield and projected payment schedule to the IRS. Pursuant to the terms of the conveyance, SandRidge and the trust have agreed (in the absence of an administrative determination or judicial ruling to the contrary) to be bound by SandRidge's determination of the comparable yield and projected payment schedule.

If, during any taxable year, the trust receives actual payments with respect to a debt instrument held by the trust that in the aggregate exceed the total amount of projected payments for that taxable year, the trust will incur a "net positive adjustment" under the CPDI regulations equal to the amount of such excess. The trust will treat a "net positive adjustment" as additional interest income for such taxable year.

If the trust receives in a taxable year actual payments with respect to a debt instrument held by the trust that in the aggregate are less than the amount of projected payments for that taxable year, the trust will incur a "net negative adjustment" under the CPDI regulations equal to the amount of such deficit. This adjustment will (a) reduce the trust's interest income on the debt instrument held by the trust for that taxable year, and (b) to the extent of any excess after the application of (a) give rise to an ordinary loss to the extent of the trust's interest income on such debt instrument during prior taxable years, reduced to the extent such interest was offset by prior net negative adjustments. Any negative adjustment in excess of the

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amount described in (a) and (b) will be carried forward, as a negative adjustment to offset future interest income in respect of that debt instrument held by the trust. If either of the Term Royalties is not treated as a production payment (and not otherwise as a debt instrument) for U.S. federal income tax purposes, the trust intends to take the position that its basis in the Term Royalty is recouped in proportion to the production from the Term Royalty.

Neither the trust nor the trust unitholders are entitled to claim depletion deductions with respect to the Term Royalties.

Tax Treatment of the Perpetual Royalties. The payments received by the trust in respect of the Perpetual Royalties treated as mineral royalty interests for U.S. federal income tax purposes should be treated as ordinary income. Trust unitholders should be entitled to deductions for the greater of either cost depletion or (if otherwise allowable) percentage depletion with respect to such income. Although the Internal Revenue Code requires each trust unitholder to compute his own depletion allowance and maintain records of his share of the adjusted tax basis of the underlying royalty interest for depletion and other purposes, the trust intends to furnish each of the trust unitholders with information relating to this computation for U.S. federal income tax purposes. Each trust unitholder, however, remains responsible for calculating his own depletion allowance and maintaining records of his share of the adjusted tax basis of the Perpetual Royalties for depletion and other purposes.

Percentage depletion is generally available with respect to trust unitholders who qualify under the independent producer exemption contained in Section 613A(c) of the Internal Revenue Code. For this purpose, an independent producer is a person not directly or indirectly involved in the retail sale of oil, oil and natural gas, or derivative products or the operation of a major refinery. Percentage depletion is calculated as an amount generally equal to 15% (and, in the case of marginal production, potentially a higher percentage) of the trust unitholder's gross income from the depletable property for the taxable year. The percentage depletion deduction with respect to any property is limited to 100% of the taxable income of the trust unitholder from the property for each taxable year, computed without the depletion allowance. A trust unitholder that qualifies as an independent producer may deduct percentage depletion only to the extent the trust unitholder's average daily production of domestic oil, or the natural gas equivalent, does not exceed 1,000 barrels. This depletable amount may be allocated between oil, natural gas and natural gas liquids production, with 6,000 cubic feet of domestic oil, natural gas and natural gas liquids production regarded as equivalent to one barrel of crude oil. The 1,000-barrel limitation must be allocated among the independent producer and controlled or related persons and family members in proportion to the respective production by such persons during the period in question.

In addition to the foregoing limitations, the percentage depletion deduction otherwise available is limited to 65% of a trust unitholder's total taxable income from all sources for the year, computed without the depletion allowance, the deduction for domestic production activities, net operating loss carrybacks, or capital loss carrybacks. Any percentage depletion deduction disallowed because of the 65% limitation may be deducted in the following taxable year if the percentage depletion deduction for such year plus the deduction carryover does not exceed 65% of the trust unitholder's total taxable income for that year. The carryover period resulting from the 65% net income limitation is unlimited.

In addition to the limitations on percentage depletion discussed above, President Obama's budget proposal for the fiscal year 2012 proposes to eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. Specifically, the budget proposes to repeal the deduction for percentage depletion with respect to wells, in which case only cost depletion would be available. It is uncertain whether this or any other legislative proposals will ever be enacted and, if so, when any such proposal would become effective.

Trust unitholders that do not qualify under the independent producer exemption are generally restricted to depletion deductions based on cost depletion. Cost depletion deductions are calculated by (a) dividing the trust unitholder's allocated share of the adjusted tax basis in the underlying mineral property by the number of mineral units (barrels of oil and thousand cubic feet of natural gas) remaining as of the beginning of the taxable year and (b) multiplying the result by the number of mineral units sold within the taxable year. The total amount of deductions based on cost depletion cannot exceed the trust unitholder's share of the total adjusted tax basis in the property.

The foregoing discussion of depletion deductions does not purport to be a complete analysis of the complex legislation and Treasury Regulations relating to the availability and calculation of depletion deductions by the trust unitholders. Further, because depletion is required to be computed separately by each trust unitholder and not by the trust, no assurance can be given, and counsel is unable to express any opinion, with respect to the availability or extent of percentage depletion deductions to the trust unitholders for any taxable year. The trust encourages each prospective trust unitholder to consult his tax advisor to determine whether percentage depletion would be available to him.

Tax Treatment Upon Sale of the Perpetual Royalties at Termination Date. The sale of the Perpetual Royalties by the trust at or shortly after the Termination Date will generally give rise to long-term capital gain or loss to the trust unitholders for U.S. federal income tax purposes, except that any gain will be taxed at ordinary income rates to the extent of depletion deductions that reduced the trust unitholder's adjusted basis in the Perpetual Royalties. Each trust unitholder will be responsible for calculating his gain or loss based on the difference between his pro-rata share of the amount realized on the sale by the trust and his adjusted basis in the Perpetual Royalties, and if a gain is realized, the portion thereof taxable as ordinary income by reason of depletion deductions previously claimed by such trust unitholder. However, the trust intends to furnish each of the trust unitholders with information relating to this calculation for U.S. federal income tax purposes in connection with the final partnership tax return for the trust.

Tax Treatment of Hedging Income. Income or loss realized with respect to hedging arrangements entered into by the trust will give rise to ordinary income or loss to the trust unitholders for U.S. federal income tax purposes. Trust unitholders will not be entitled to depletion deductions with respect to any hedging income.

Limitations on Deductibility of Losses. It is not anticipated that the trust will generate losses. Nevertheless, should losses result, trust unitholders must consult their own tax advisors as to the applicability to them of loss limitation rules that could operate to limit the deductibility to a trust unitholder of his share of the trust's losses such as the basis limitation, the "at risk" rules and the passive loss rules. Special passive loss limitation rules apply with respect to publicly-traded partnerships.

Limitations on Interest Deductions. The deductibility of a non-corporate taxpayer's "investment interest expense" is generally limited to the amount of that taxpayer's "net investment income." Investment interest expense includes:

- interest on indebtedness properly allocable to property held for investment;
- the trust's interest expense attributed to portfolio income; and
- the portion of interest expense incurred to purchase or carry an interest in a passive activity to the extent attributable to portfolio income.

The computation of a trust unitholder's investment interest expense will take into account interest on any margin account borrowing or other loan incurred to purchase or carry a trust unit. Net investment income includes gross income from property held for investment and amounts treated as portfolio income under the passive loss rules, less deductible expenses, other than interest, directly connected with the production of investment income, but generally does not include gains attributable to the disposition of property held for investment or qualified dividend income. The IRS has indicated that the net passive income earned by a publicly traded partnership will be treated as investment income to its unitholders for purposes of the investment interest deduction limitation. In addition, the trust unitholder's share of the trust's portfolio income will be treated as investment income.

Entity-Level Withholdings. If the trust is required or elects under applicable law to pay any federal, state, local or foreign income tax on behalf of any trust unitholder or any former trust unitholder, the trust

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is authorized to pay those taxes from its funds. That payment, if made, will be treated as a distribution of cash to the trust unitholder on whose behalf the payment was made. If the payment is made on behalf of a person whose identity cannot be determined, the trust is authorized to treat the payment as a distribution to all current trust unitholders. The trust is authorized to amend its trust agreement in the manner necessary to maintain uniformity of intrinsic tax characteristics of trust units. Payments by the trust as described above could give rise to an overpayment of tax on behalf of an individual trust unitholder in which event the trust unitholder would be required to file a claim in order to obtain a credit or refund.

Treatment of Short Sales. A trust unitholder whose trust units are loaned to a "short seller" to cover a short sale of trust units may be considered as having disposed of those units. If so, he would no longer be treated for tax purposes as a partner with respect to those trust units during the period of the loan and may recognize gain or loss from the disposition. As a result, during this period:

- any of the trust's income, gain, loss, deduction or credit with respect to those trust units would not be reportable by the trust unitholder;

- any cash distributions received by the trust unitholder as to those trust units would be fully taxable; and

- all of these distributions would appear to be ordinary income.

Covington & Burling LLP has not rendered an opinion regarding the tax treatment of a trust unitholder whose trust units are loaned to a short seller to cover a short sale of trust units; therefore, trust unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their trust units. The IRS has previously announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please also read " Disposition of Trust Units Recognition of Gain or Loss."

Alternative Minimum Tax. Each trust unitholder will be required to take into account his distributive share of any items of the trust's income, gain, loss, deduction or credit for purposes of the alternative minimum tax. The current minimum tax rate for non-corporate taxpayers is 26% on the first $175,000 of alternative minimum taxable income in excess of the exemption amount and 28% on any additional alternative minimum taxable income. Prospective trust unitholders are urged to consult with their tax advisors as to the impact of an investment in trust units on their liability for the alternative minimum tax.

Tax Rates. Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 35% and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, capital gains on certain assets held for more than 12 months) of individuals is 15%. However, absent new legislation extending the current rates, beginning January 1, 2013, the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. Moreover, these rates are subject to change by new legislation at any time.

The recently enacted Health Care and Education Reconciliation Act of 2010 will impose a 3.8% Medicare tax on certain investment income earned by individuals, estates and trusts for taxable years beginning after December 31, 2012. For these purposes, investment income generally includes a trust unitholder's allocable share of the trust's income and gain realized by a trust unitholder from a sale of trust units. In the case of an individual, the tax will be imposed on the lesser of (1) the trust unitholder's net income from all investments, and (2) the amount by which the trust unitholder's adjusted gross income exceeds $250,000 (if the trust unitholder is married and filing jointly or a surviving spouse), $125,000 (if the trust unitholder is married and filing separately) or $200,000 (if the trust unitholder is not married). In the case of an estate or trust, the tax will be imposed on the lesser of (1) the undistributed net investment income of the estate or trust, or (2) the excess of the adjusted gross income of the estate or trust over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

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Section 754 Election. The trust will make the election permitted by Section 754 of the Internal Revenue Code. That election is irrevocable without the consent of the IRS. The election will generally permit the trust to adjust a subsequent trust unit purchaser's tax basis in the trust's assets ("inside basis") under Section 743(b) of the Internal Revenue Code to reflect his purchase price of trust units acquired from another trust unitholder. The Section 743(b) adjustment belongs to the purchaser and not to other trust unitholders. For purposes of this discussion, a trust unitholder's inside basis in the trust's assets will be considered to have two components: (1) his share of tax basis in the trust's assets ("common basis") and (2) his Section 743(b) adjustment to that basis.

A Section 754 election is advantageous if the transferee's tax basis in his units is higher than the units' share of the aggregate tax basis of the trust's assets immediately prior to the transfer. In such a case, as a result of the election, the transferee would have a higher tax basis in his share of the trust's assets for purposes of calculating, among other items, cost depletion deductions on the Perpetual Royalties, and his share of any gain on a sale of the trust's assets would be less. Conversely, a Section 754 election is disadvantageous if the transferee's tax basis in his units is lower than those trust units' share of the aggregate tax basis of the trust's assets immediately prior to the transfer. Thus, the fair market value of the trust units may be affected either favorably or unfavorably by the election. A basis adjustment is required regardless of whether a Section 754 election is made in the case of a transfer of an interest in the trust if it has a substantial built-in loss immediately after the transfer. Generally a built-in loss or a basis reduction is substantial if it exceeds $250,000.

The calculations involved in the Section 754 election are complex and will be made on the basis of assumptions as to the value of the trust's assets and other matters. For example, the allocation of the Section 743(b) adjustment among the trust's assets must be made in accordance with the Internal Revenue Code. The trust cannot assure unitholders that the determinations it makes will not be successfully challenged by the IRS and that the deductions resulting from them will not be reduced or disallowed altogether. Should the IRS require a different basis adjustment to be made, and should, in the trust's opinion, the expense of compliance exceed the benefit of the election, the trust may seek permission from the IRS to revoke its Section 754 election. If permission is granted, a subsequent purchaser of trust units may be allocated more income than he would have been allocated had the election not been revoked.

Initial Tax Basis and Amortization. The initial tax basis of the portion of the PDP Royalty Interest treated as a royalty interest in minerals (the Perpetual PDP Royalty) and the portion treated as a production payment (the Term PDP Royalty), and the initial basis of the portion of the Development Royalty Interest treated as a royalty interest in minerals (the Perpetual Development Royalty) and the portion treated as a production payment (the Term Development Royalty) will be effectively equal on a per-unit basis to the portion of the unit price allocated to each based on each such portion's relative fair market value.

The costs incurred in selling the trust units (called "syndication expenses") must be capitalized and cannot be deducted currently, ratably or upon the trust's termination. There are uncertainties regarding the classification of costs as organizational expenses, which may be amortized by the trust, and as syndication expenses, which may not be amortized by the trust. The underwriting discounts and commissions the trust incurs will be treated as syndication expenses.

Valuation and Tax Basis of the Trust's Properties. The U.S. federal income tax consequences of the ownership and disposition of trust units will depend in part on the trust's estimates of the relative fair market values, and the initial tax bases, of the trust's assets. Although the trust may from time to time consult with professional appraisers regarding valuation matters, the trust will make many of the relative fair market value estimates itself. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by trust unitholders might change, and trust unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

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Disposition of Trust Units

Recognition of Gain or Loss. Gain or loss will be recognized on a sale of trust units equal to the difference between the amount realized and the trust unitholder's tax basis for the trust units sold. A trust unitholder's amount realized will be measured by the sum of the cash or the fair market value of other property received. The amount realized should be reduced by the unused net negative adjustments attributable to the trust units disposed of as described above under " Tax Consequences of Trust Unit Ownership Tax Treatment of the Term Royalties." A trust unitholder's adjusted tax basis in his trust units will be equal to the trust unitholder's original purchase price for the trust units, increased by income and decreased by losses or deductions previously allocated to the trust unitholder and by distributions to the trust unitholder and depletion deductions claimed by the trust unitholder.

Prior distributions from the trust in excess of cumulative net taxable income for a trust unit that decreased a unitholder's tax basis in that trust unit will, in effect, become taxable income if the trust unit is sold at a price greater than the trust unitholder's tax basis in that trust unit, even if the price received is less than his original cost.

Except as noted below, gain or loss recognized by a trust unitholder, other than a "dealer" in trust units, on the sale or exchange of a trust unit will generally be taxable as capital gain or loss. Capital gain recognized by an individual on the sale of trust units held for more than 12 months will generally be taxed at a maximum U.S. federal income tax rate of 15% through December 31, 2012 and 20% thereafter (absent new legislation extending or adjusting the current rate). However, a portion, which will likely be substantial, of this gain or loss will be separately computed and taxed as ordinary income or loss under Section 751 of the Internal Revenue Code to the extent attributable to assets giving rise to "unrealized receivables" the trust owns. The term "unrealized receivables" includes potential recapture items, including depletion recapture. Ordinary income attributable to unrealized receivables such as depletion recapture may exceed net taxable gain realized upon the sale of a trust unit and may be recognized even if there is a net taxable loss realized on the sale of a trust unit. Thus, a trust unitholder may recognize both ordinary income and a capital loss upon a sale of trust units. Net capital losses may offset capital gains and no more than $3,000 of ordinary income, in the case of individuals, and may only be used to offset capital gains in the case of corporations.

The IRS has ruled that a partner who acquires interests in a partnership in separate transactions must combine those interests and maintain a single adjusted tax basis for all those interests. Upon a sale or other disposition of less than all of those interests, a portion of that tax basis must be allocated to the interests sold using an "equitable apportionment" method, which generally means that the tax basis allocated to the interest sold equals an amount that bears the same relation to the partner's tax basis in his entire interest in the partnership as the value of the interest sold bears to the value of the partner's entire interest in the partnership. Treasury Regulations under Section 1223 of the Internal Revenue Code allow a selling trust unitholder who can identify trust units transferred with an ascertainable holding period to elect to use the actual holding period of the trust units transferred. Thus, according to the ruling discussed above, a trust unitholder will be unable to select high or low basis trust units to sell as would be the case with corporate stock, but, according to the Treasury Regulations, he may designate specific trust units sold for purposes of determining the holding period of trust units transferred. A trust unitholder electing to use the actual holding period of trust units transferred must consistently use that identification method for all subsequent sales or exchanges of trust units. A trust unitholder considering the purchase of additional trust units or a sale of trust units purchased in separate transactions is urged to consult his tax advisor as to the possible consequences of this ruling and application of the Treasury Regulations.

Specific provisions of the Internal Revenue Code affect the taxation of some financial products and securities, including partnership interests, by treating a taxpayer as having sold an "appreciated" partnership interest, one in which gain would be recognized if it were sold, assigned or terminated at its fair market value, if the taxpayer or related persons enter(s) into:

- a short sale;

- an offsetting notional principal contract; or

- a futures or forward contract with respect to the partnership interest or substantially identical property.

Moreover, if a taxpayer has previously entered into a short sale, an offsetting notional principal contract or a futures or forward contract with respect to the partnership interest, the taxpayer will be treated as having sold that position if the taxpayer or a related person then acquires the partnership interest or substantially identical property. The Secretary of the Treasury is also authorized to issue regulations that treat a taxpayer that enters into transactions or positions that have substantially the same effect as the preceding transactions as having constructively sold the financial position.

Allocations Between Transferors and Transferees. In general, the trust's taxable income and losses will be determined and allocated on a quarterly basis and apportioned among the trust unitholders in proportion to the number of trust units of record owned by each of them as of the opening of the applicable exchange on which the trust units are then traded on the quarterly record date occuring in such quarter, which is referred to in this prospectus as the "Allocation Date."

Although simplifying conventions are contemplated by the Internal Revenue Code, the use of this method may not be permitted under existing Treasury Regulations. Accordingly, Covington & Burling LLP is unable to opine on the validity of this method of allocating income and deductions between transferor and transferee trust unitholders. If this method is not allowed under the Treasury Regulations, or only applies to transfers of less than all of the trust unitholder's interest, the trust's taxable income or losses might be reallocated among the trust unitholders. The trust is authorized to revise its method of allocation between transferor and transferee trust unitholders, as well as trust unitholders whose interests vary during a taxable year, to conform to a method permitted under future Treasury Regulations.

Notification Requirements. A trust unitholder who sells any of his trust units is generally required to notify the trust in writing of that sale within 30 days after the sale (or, if earlier, January 15 of the year following the sale). A purchaser of trust units who purchases trust units from another trust unitholder is also generally required to notify the trust in writing of that purchase within 30 days after the purchase. Upon receiving such notifications, the trust is required to notify the IRS of that transaction and to furnish specified information to the transferor and transferee. Failure to notify the trust of a purchase may, in some cases, lead to the imposition of penalties. However, these reporting requirements do not apply to a sale by an individual who is a citizen of the United States and who affects the sale or exchange through a broker who will satisfy such requirements.

Constructive Termination. The trust will be considered to have been terminated for tax purposes if there are sales or exchanges which, in the aggregate, constitute 50% or more of the total interests in the trust's capital and profits within a twelve-month period. For purposes of measuring whether the 50% threshold is reached, multiple sales of the same interest are counted only once. A constructive termination results in the closing of the trust's taxable year for all trust unitholders. In the case of a trust unitholder reporting on a taxable year other than a calendar year, the closing of the trust's taxable year may result in more than 12 months of the trust's taxable income or loss being includable in his taxable income for the year of termination. A constructive termination occurring on a date other than December 31 will result in the trust filing two tax returns (and trust unitholders may receive two Schedule K-1's) for one fiscal year and the cost of the preparation of these returns will be borne by all trust unitholders. The trust would be required to make new tax elections after a termination, including a new election under Section 754 of the Internal Revenue Code. A termination could also result in penalties if the trust was unable to determine that the termination had occurred. Moreover, a termination might either accelerate the application of, or subject the trust to, any tax legislation enacted before the termination.

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Tax-Exempt Organizations and Certain Other Investors

Ownership of trust units by employee benefit plans, other tax-exempt organizations, non-resident aliens, non-U.S. corporations and other non-U.S. persons raises issues unique to those investors and, as described below, may have substantially adverse tax consequences to them. If a potential investor is a tax-exempt entity or a non-U.S. person, then it should consult a tax advisor before investing in the trust units.

Tax-Exempt Organizations. Employee benefit plans and most other organizations exempt from U.S. federal income tax including IRAs and other retirement plans are subject to U.S. federal income tax on unrelated business taxable income. Because all of the income of the trust is expected to be royalty income, interest income, hedging income and gain from the sale of real property, none of which is unrelated business taxable income, any such organization exempt from U.S. federal income tax is not expected to be taxable on income generated by ownership of trust units so long as neither the property held by the trust nor the trust units are debt-financed property within the meaning of Section 514(b) of the Internal Revenue Code. In general, trust property would be debt-financed if the trust incurs debt to acquire the property or otherwise incurs or maintains a debt that would not have been incurred or maintained if the property had not been acquired and a trust unit would be debt-financed if the trust unitholder incurs debt to acquire the trust unit or otherwise incurs or maintains a debt that would not have been incurred or maintained if the trust unit had not been acquired.

Non-U.S. Persons. The trust (or the appropriate intermediary if units are held in "Street Name") will be required to withhold (at a 30% rate or lower applicable treaty rate) on interest and royalty income paid to non-U.S. trust unitholders.

Moreover, each of the PDP Royalty Interest and the Development Royalty Interest will be treated as a "United States real property interest" for U.S. federal income tax purposes. However, as long as the trust units are regularly traded on an established securities market, gain realized by a non-U.S. trust unitholder on a sale of trust units will be subject to U.S. federal income tax only if:

- the gain is, or is treated as, effectively connected with business conducted by the non-U.S. trust unitholder in the United States, and in the case of an applicable tax treaty, is attributable to a U.S. permanent establishment maintained by the non-U.S. trust unitholder;

- the non-U.S. trust unitholder is an individual who is present in the United States for at least 183 days in the year of the sale and certain other conditions are met; or

- the non-U.S. trust unitholder owns currently, or owned at certain earlier times, directly or by applying certain attribution rules, more than 5% of the trust units.

Gain realized by a non-U.S. trust unitholder upon the sale or other taxable disposition by the trust of any PDP Royalty Interest or Development Royalty Interest would be subject to U.S. federal income tax, and distributions to the non-U.S. trust unitholder would be subject to withholding of U.S. tax (currently at the rate of 35%) to the extent distributions are attributable to such gains.

Administrative Matters

Trust Information Returns and Audit Procedures. The trust intends to furnish to each trust unitholder, within 90 days after the close of each calendar year, specific tax information, including a Schedule K-1, which describes his share of the trust's income, gain, loss and deduction for the trust's preceding taxable year. In preparing this information, which will not be reviewed by counsel, the trust will take various accounting and reporting positions, some of which have been mentioned earlier, to determine each trust unitholder's share of income, gain, loss and deduction. The trust cannot assure unitholders that those positions will yield a result that conforms to the requirements of the Internal Revenue Code, Treasury Regulations or administrative interpretations of the IRS. Neither the trust nor Covington & Burling LLP can assure prospective trust unitholders that the IRS will not successfully contend in court that those positions are impermissible. Any challenge by the IRS could negatively affect the value of the units.

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The IRS may audit the trust's U.S. federal income tax information returns. Adjustments resulting from an IRS audit may require each trust unitholder to adjust a prior year's tax liability, and possibly may result in an audit of his return. Any audit of a trust unitholder's return could result in adjustments not related to the trust's returns as well as those related to the trust's returns.

Partnerships generally are treated as separate entities for purposes of federal tax audits, judicial review of administrative adjustments by the IRS and tax settlement proceedings. The tax treatment of partnership items of income, gain, loss and deduction are determined in a partnership proceeding rather than in separate proceedings with the partners. The Internal Revenue Code requires that one partner be designated as the "Tax Matters Partner" for these purposes. The trust agreement names SandRidge as the trust's Tax Matters Partner.

The Tax Matters Partner has made and will make some elections on behalf of the trust and the trust unitholders. In addition, the Tax Matters Partner can extend the statute of limitations for assessment of tax deficiencies against trust unitholders for items in the trust's returns. The Tax Matters Partner may bind a trust unitholder with less than a 1% profits interest in the trust to a settlement with the IRS unless that trust unitholder elects, by filing a statement with the IRS, not to give that authority to the Tax Matters Partner. The Tax Matters Partner may seek judicial review, by which all the trust unitholders are bound, of a final partnership administrative adjustment and, if the Tax Matters Partner fails to seek judicial review, judicial review may be sought by any trust unitholder having at least a 1% interest in profits or by any group of trust unitholders having in the aggregate at least a 5% interest in profits. However, only one action for judicial review will go forward, and each trust unitholder with an interest in the outcome may participate.

A trust unitholder must file a statement with the IRS identifying the treatment of any item on his federal income tax return that is not consistent with the treatment of the item on the trust's return. Intentional or negligent disregard of this consistency requirement may subject a trust unitholder to substantial penalties.

Nominee Reporting. Persons who hold an interest in the trust as a nominee for another person are required to furnish to the trust:

(a) the name, address and taxpayer identification number of the beneficial owner and the nominee;

(b) whether the beneficial owner is:

(1) a person that is not a United States person;

(2) a non-U.S. government, an international organization or any wholly owned agency or instrumentality of either of the foregoing; or

(3) a tax-exempt entity;

(c) the amount and description of units held, acquired or transferred for the beneficial owner; and

(d) specific information including the dates of acquisitions and transfers, means of acquisitions and transfers and acquisition cost for purchases, as well as the amount of net proceeds from sales.

Brokers and financial institutions are required to furnish additional information, including whether they are United States persons and specific information on units they acquire, hold or transfer for their own account. A penalty of $100 per failure, up to a maximum of $1,500,000 per calendar year, is imposed by the Internal Revenue Code for failure to report that information to the trust. The nominee is required to supply the beneficial owner of the trust units with the information furnished to the trust.

Accuracy-Related Penalties. An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements,

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is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

For individuals, a substantial understatement of income tax in any taxable year exists if the amount of the understatement exceeds the greater of 10% of the tax required to be shown on the return for the taxable year or $5,000. The amount of any understatement subject to penalty generally is reduced if any portion is attributable to a position adopted on the return:

(1) for which there is, or was, "substantial authority"; or

(2) as to which there is a reasonable basis and the pertinent facts of that position are disclosed on the return.

If any item of income, gain, loss or deduction included in the distributive shares of trust unitholders might result in that kind of an "understatement" of income for which no "substantial authority" exists, the trust must disclose the pertinent facts on its return. In addition, the trust will make a reasonable effort to furnish sufficient information for trust unitholders to make adequate disclosure on their returns and to take other actions as may be appropriate to permit trust unitholders to avoid liability for this penalty. More stringent rules apply to "tax shelters," which the trust does not believe includes it, or any of the trust's investments, plans or arrangements.

A substantial valuation misstatement exists if (a) the value of any property, or the tax basis of any property, claimed on a tax return is 150% or more of the amount determined to be the correct amount of the valuation or tax basis, (b) the price for any property or services (or for the use of property) claimed on any such return with respect to any transaction between persons described in Internal Revenue Code Section 482 is 200% or more (or 50% or less) of the amount determined under Section 482 to be the correct amount of such price, or (c) the net Internal Revenue Code Section 482 transfer price adjustment for the taxable year exceeds the lesser of $5 million or 10% of the taxpayer's gross receipts.

No penalty is imposed unless the portion of the underpayment attributable to a substantial valuation misstatement exceeds $5,000 ($10,000 for most corporations). The penalty is increased to 40% in the event of a gross valuation misstatement. The trust does not anticipate making any valuation misstatements.

Reportable Transactions. If the trust were to engage in a "reportable transaction," the trust (and possibly the unitholders) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a "listed transaction" or that it produces certain kinds of losses for partnerships, individuals, S corporations, and trusts in excess of $2 million in any single year, or $4 million in any combination of 6 successive tax years. The trust's participation in a reportable transaction could increase the likelihood that the trust's U.S. federal income tax information return (and possibly the unitholders' tax return) would be audited by the IRS. Please read " Trust Information Returns and Audit Procedures."

Moreover, if the trust were to participate in a reportable transaction with a significant purpose to avoid or evade tax, or in any listed transaction, unitholders may be subject to the following provisions of the American Jobs Creation Act of 2004:

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at " Accuracy-Related Penalties";

- for those persons otherwise entitled to deduct interest on federal tax deficiencies, non-deductibility of interest on any resulting tax liability; and

- in the case of a listed transaction, an extended statute of limitations.

The trust does not expect to engage in any "reportable transactions."

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STATE TAX CONSIDERATIONS

The following is intended as a brief summary of certain information regarding state income taxes. No opinion of counsel has been requested or received with respect to the state tax consequences of an investment in trust units. Trust unitholders are urged to consult their own legal and tax advisors with respect to these matters.

Prospective investors should consider state and local income tax consequences of an investment in the common units. The trust will own royalty interests burdening specified oil and natural gas properties located in Andrews County, Texas and will be subject at the trust level to the Texas franchise tax. Texas does not currently impose a state-level personal income tax applicable to individuals. The trust should not be required to withhold state income tax on distributions made to an individual resident or nonresident trust unitholder.

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ERISA CONSIDERATIONS

The Employee Retirement Income Security Act of 1974, as amended (referred to as "ERISA"), regulates qualified pension plans, profit-sharing plans, stock bonus plans, simplified employee pension plans, Keogh plans, tax deferred annuities or IRAs established or maintained by an employer or employee organization, and other employee benefit plans to which it applies. ERISA also contains standards for persons who are fiduciaries of those plans. In addition, the Internal Revenue Code provides similar requirements and standards which are applicable to qualified plans, which include these types of plans, and to individual retirement accounts, whether or not subject to ERISA.

A fiduciary of a qualified plan should carefully consider fiduciary standards under ERISA regarding the qualified plan's particular circumstances before authorizing an investment in trust units. Among other things, a fiduciary should consider:

- whether the investment satisfies the prudence requirements of Section 404(a)(1)(B) of ERISA;

- whether the investment satisfies the diversification requirements of Section 404(a)(1)(C) of ERISA; and

- whether the investment is in accordance with the documents and instruments governing the qualified plan as required by Section 404(a)(1)(D) of ERISA.

A fiduciary should also consider whether an investment in common units might result in direct or indirect nonexempt prohibited transactions under Section 406 of ERISA and Internal Revenue Code Section 4975. In deciding whether an investment involves a prohibited transaction, a fiduciary must determine whether there are plan assets in the transaction. The Department of Labor has published regulations concerning whether or not a qualified plan's assets would be deemed to include an interest in the underlying assets of an entity for purposes of the reporting, disclosure and fiduciary responsibility provisions of ERISA and analogous provisions of the Internal Revenue Code. These regulations provide that the underlying assets of an entity will not be considered "plan assets" if the equity interests in the entity are a publicly offered security. SandRidge expects that at the time of the sale of the trust units in this offering, they will be publicly offered securities.

However, the prohibited transaction rules are complex, and persons involved in prohibited transactions are subject to penalties. For that reason, potential qualified plan investors should consult with their counsel to determine the consequences under ERISA and the Internal Revenue Code of their acquisition and ownership of trust units.

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UNDERWRITERS

Subject to the terms and conditions in an underwriting agreement dated August 10, 2011, the underwriters named below, for whom Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC and Wells Fargo Securities, LLC, acting as representatives, have severally agreed to purchase from SandRidge the number of trust units set forth opposite their names:

Name	Number of Trust Units
Morgan Stanley & Co. LLC	6,300,000
Raymond James & Associates, Inc.	5,100,000
RBC Capital Markets, LLC	3,000,000
Wells Fargo Securities, LLC	3,000,000
Deutsche Bank Securities Inc.	2,100,000
Goldman, Sachs & Co.	2,100,000
J.P. Morgan Securities LLC	2,100,000
Robert W. Baird & Co. Incorporated	1,200,000
Oppenheimer & Co. Inc.	1,200,000
Morgan Keegan & Company, Inc.	900,000
Sanders Morris Harris Inc.	900,000
Wunderlich Securities, Inc.	900,000
SunTrust Robinson Humphrey, Inc.	600,000
Johnson Rice & Company L.L.C.	450,000
Tuohy Brothers Investment Research, Inc.	150,000
Total	30,000,000

The underwriters and the representatives are collectively referred to as the "underwriters" and the "representatives," respectively. The underwriters are obligated to take and pay for all of the common units offered by this prospectus, if any are taken, other than the common units covered by the option described below unless and until this option is exercised. The underwriting agreement provides that the obligations of the several underwriters to pay for and accept delivery of the common units are subject to a number of conditions, including, among others, the accuracy of the representations and warranties in the underwriting agreement, listing of the common units on the New York Stock Exchange, receipt of specified letters from counsel and the trust's and SandRidge's independent registered public accounting firm, and receipt of specified officers' certificates.

Common units sold by the underwriters to the public will initially be offered at the initial public offering price set forth on the cover page of this prospectus. Any common units sold by the underwriters to securities dealers may be sold at a price that represents a concession not in excess of $0.648 per common unit under the initial public offering price. If all of the common units are not sold at the initial public offering price, the offering price and other selling terms may from time to time be varied by the representatives. The offering of the common units by the underwriters is subject to receipt and acceptance and subject to the underwriters' right to reject any order in whole or in part.

The trust has granted the underwriters an option to buy up to 4,500,000 additional common units from the trust at the public offering price listed on the cover page of this prospectus, less underwriting discounts and commissions. They may exercise that option for 30 days from the date of this prospectus. To the extent the option is exercised, each underwriter will become obligated, subject to certain conditions, to purchase the same percentage of the additional common units as the number listed next to the underwriter's name in the preceding table bears to the total number of common units listed next to the names of all underwriters in the preceding table.

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If the underwriters do not exercise their option to purchase additional common units, the trust will issue 4,500,000 common units to SandRidge upon the option's expiration. If and to the extent the underwriters exercise their option to purchase additional common units, the number of common units purchased by the underwriters pursuant to such exercise will be issued to the public and the remainder, if any, will be issued to SandRidge. Accordingly, the exercise of the underwriters' option will not affect the total number of common units outstanding.

The following table shows the amount per unit and total underwriting discounts the trust will pay to the underwriters. The amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase additional trust units.

		Total	
	Per Unit	**No Exercise**	**Full Exercise**
Public Offering Price	$ 18.00	$ 540,000,000	$ 621,000,000
Underwriting discounts and commissions	$ 1.08	$ 32,400,000	$ 37,260,000
Proceeds, before expenses	$ 16.92	$ 507,600,000	$ 583,740,000

The trust will pay Morgan Stanley & Co. LLC a structuring fee of $2,700,000 (or $3,105,000 if the underwriters exercise their option to purchase additional trust units to cover over-allotments) for evaluation, analysis and structuring of the trust.

SandRidge estimates that the expenses payable by SandRidge or the trust, excluding underwriting discounts and commissions, will be approximately $2.35 million.

The underwriters have informed the trust that they do not intend sales to discretionary accounts to exceed 5% of the total number of common units offered by them.

The trust's common units have been approved for listing on the New York Stock Exchange under the symbol "PER."

SandRidge has agreed with the underwriters, subject to specified exceptions, not to dispose of or hedge any of the common units or securities convertible into or exchangeable for common units during the period from the date of the preliminary prospectus continuing through the date 180 days after the date of this prospectus, except with the prior written consent of Morgan Stanley & Co. LLC, Raymond James & Associates, Inc., RBC Capital Markets, LLC and Wells Fargo Securities, LLC.

The 180-day restricted period described in the preceding paragraph will be automatically extended if: (1) during the last 17 days of the 180-day restricted period the trust issues a release concerning distributable cash or announces material news or a material event relating to the trust occurs; or (2) prior to the expiration of the 180-day restricted period, the trust announces that it will release distributable cash during the 16-day period following the last day of the 180-day period, in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18-day period beginning on the issuance of the earnings release or the announcement of the material news or material event.

The underwriters have informed SandRidge that they do not presently intend to release common units or other securities subject to the lock-up agreements. Any determination to release any common units or other securities subject to the lock-up agreements would be based on a number of factors at the time of any such determination; such factors may include the market price of the common units, the liquidity of the trading market for the common units, general market conditions, the number of common units or other securities subject to the lock-up agreements proposed to be sold, and the timing, purpose and terms of the proposed sale.

In order to facilitate the offering of the common units, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the common units. Specifically, the underwriters may sell more units than they are obligated to purchase under the underwriting agreement, creating a short position. A short sale is covered if the short position is no greater than the number of units available for purchase by the underwriters under the over-allotment option. The underwriters can close out a covered short sale by exercising the over-allotment option or purchasing units in the open market. In determining the source of units to close out a covered short sale, the underwriters will consider, among other things, the open market price of units compared to the price available under the over-allotment option. The underwriters may also sell units in excess of the over-allotment option, creating a naked short position. The underwriters must close out any naked short position by purchasing units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in this offering. As an additional means of facilitating this offering, the underwriters may bid for, and purchase, common units in the open market to stabilize the price of the common units. These activities may raise or maintain the market price of the common units above independent market levels or prevent or retard a decline in the market price of the common units. The underwriters are not required to engage in these activities and may end any of these activities at any time.

The underwriters may also impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the representatives have repurchased units sold by or for the account of such underwriter in stabilizing or short covering transactions.

SandRidge has agreed to indemnify the several underwriters and persons who control the underwriters against certain liabilities that may arise in connection with this offering, including liabilities under the Securities Act of 1933.

Because the Financial Industry Regulatory Authority, or FINRA, views the common units offered under this prospectus as interests in a direct participation program, the offering is being made in compliance with Rule 2310 of the FINRA rules administered by FINRA. Investor suitability with respect to the common units should be judged similarly to the suitability with respect to other securities that are listed for quotation on a national securities exchange.

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various financial advisory, investment banking, commercial banking and other services for SandRidge, for which they received or will receive customary fees and expenses. In addition, affiliates of certain of the underwriters may be counterparties under the direct hedging contracts with the trust. Furthermore, certain of the underwriters and their respective affiliates may, from time to time, enter into arms-length transactions with SandRidge in the ordinary course of their business. In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments, including serving as counterparties to certain derivative and hedging arrangements, and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve securities or instruments of the trust or SandRidge. The underwriters and their respective affiliates may also make investment recommendations or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long or short positions in such securities and instruments.

A prospectus in electronic format may be made available on websites maintained by one or more underwriters, or selling group members, if any, participating in this offering. The representatives may agree to allocate a number of common units to underwriters for sale to their online brokerage account holders.

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Internet distributions will be allocated by the representatives to the underwriters that may make Internet distributions on the same basis as other allocations.

Pricing of the Offering

Prior to this offering, there has been no public market for trust units. The initial public offering price was determined by negotiations between SandRidge and the representatives. Among the factors considered in determining the initial public offering price were estimates of distributions to trust unitholders, overall quality of the oil, natural gas and natural gas liquids to the Underlying Properties, industry and market conditions, prevalent in the energy industry, the information set forth in this prospectus and otherwise available to the representatives and the general conditions of the securities market at the time of this offering.

The estimated initial public offering price range set forth on the cover page of this prospectus is subject to change as a result of market conditions and other factors. The trust cannot assure you that the prices at which the common units will sell in the public market after this offering will not be lower than the initial public offering price or that an active trading market in the trust's common units will develop and continue after this offering.

Directed Unit Program

At SandRidge's request, the underwriters have reserved up to 5% of the common units being offered by this prospectus for sale to SandRidge's directors, officers, and certain other persons associated with SandRidge, at the initial public offering price. The sales will be made by Morgan Stanley & Co. LLC through a directed unit program. It is not certain if these persons will choose to purchase all or any portion of these reserved units, but any purchases they make will reduce the number of common units available to the general public. To the extent the allotted reserved units are not purchased in the directed unit program, we will offer these common units to the general public on the same basis as all other common units offered by this prospectus. The individuals eligible to participate in the directed unit program must commit to purchase no later than before the opening of business on the day following the date of this prospectus, but in any event, will not be obligated to purchase common units. Any directors or officers of SandRidge or other persons associated with SandRidge purchasing reserved units in the directed unit program, if any, will not be subject to a lock-up agreement. SandRidge has agreed to indemnify Morgan Stanley & Co. LLC against certain liabilities and expenses, including liabilities under the Securities Act of 1933, in connection with the sales of the reserved units.

Conflicts/Affiliates

The underwriters and their affiliates may provide in the future investment banking, financial advisory or other financial services for SandRidge and its affiliates, for which they may receive advisory or transaction fees, as applicable, plus out-of-pocket expense, of the nature and in amounts customary to the industry for these financial services. Affiliates of Morgan Stanley & Co. LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co., J.P. Morgan Securities LLC, RBC Capital Markets, LLC, SunTrust Robinson Humphrey, Inc. and Wells Fargo Securities, LLC are lenders under the SandRidge credit facility being repaid with the offering proceeds being paid to SandRidge and will therefore receive a portion of the proceeds of the offering.

Notice to Prospective Investors in the EEA

In relation to each member state of the European Economic Area that has implemented the Prospectus Directive (each, a relevant member state), with effect from and including the date on which the Prospectus Directive is implemented in that relevant member state (the relevant implementation date), an offer of securities described in this prospectus may not be made to the public in that relevant member state other than:

- to any legal entity which is a qualified investor as defined in the Prospectus Directive;
- to fewer than 100 or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, 150, natural or legal persons (other than qualified investors as defined in the Prospectus Directive), as permitted under the Prospectus Directive, subject to obtaining the prior consent of the relevant Dealer or Dealers nominated by the Issuer for any such offer; or
- in any other circumstances falling within Article 3(2) of the Prospectus Directive;

provided that no such offer of securities shall require us or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For purposes of this provision, the expression an "offer of securities to the public" in any relevant member state means the communication in any form and by any means of sufficient information on the terms of the offer and the securities to be offered so as to enable an investor to decide to purchase or subscribe for the securities, as the expression may be varied in that member state by any measure implementing the Prospectus Directive in that member state, and the expression "Prospectus Directive" means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member State), and includes any relevant implementing measure in the Relevant Member State, and includes any relevant implementing measure in each relevant member state. The expression "2010 PD Amending Directive" means Directive 2010/73/EU.

We have not authorized and do not authorize the making of any offer of securities through any financial intermediary on their behalf, other than offers made by the underwriters with a view to the final placement of the securities as contemplated in this prospectus. Accordingly, no purchaser of the securities, other than the underwriters, is authorized to make any further offer of the securities on behalf of us or the underwriters.

Notice to Prospective Investors in the United Kingdom

The trust may constitute a "collective investment scheme" as defined by section 235 of the Financial Services and Markets Act 2000 (FSMA) that is not a "recognized collective investment scheme" for the purposes of FSMA (CIS) and that has not been authorized or otherwise approved. As an unregulated scheme, it cannot be marketed in the United Kingdom to the general public, except in accordance with FSMA. This prospectus is only being distributed in the United Kingdom to, and is only directed at:

(1) if the trust is a CIS and is marketed by a person who is an authorized person under FSMA, (a) investment professionals falling within Article 14(5) of the Financial Services and Markets Act 2000 (Promotion of Collective Investment Schemes) Order 2001, as amended (the CIS Promotion Order) or (b) high net worth companies and other persons falling within Article 22(2)(a) to (d) of the CIS Promotion Order; or

(2) otherwise, if marketed by a person who is not an authorized person under FSMA, (a) persons who fall within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the Financial Promotion Order) or (b) Article 49(2)(a) to (d) of the Financial Promotion Order; and

(3) in both cases (1) and (2) to any other person to whom it may otherwise lawfully be made (all such persons together being referred to as "relevant persons").

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The common units are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such common units will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents.

An invitation or inducement to engage in investment activity (within the meaning of Section 21 of FSMA) in connection with the issue or sale of any common units which are the subject of the offering contemplated by this prospectus will only be communicated or caused to be communicated in circumstances in which Section 21(1) of FSMA does not apply to the trust.

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LEGAL MATTERS

Richards, Layton & Finger, P.A., as special Delaware counsel to the trust, will give a legal opinion as to the validity of the trust units. Covington & Burling LLP, counsel to SandRidge, will give opinions as to certain other matters relating to the offering, including the tax opinion described in the section of this prospectus captioned "U.S. Federal Income Tax Considerations." Certain legal matters in connection with the common units offered hereby will be passed upon for the underwriters by Vinson & Elkins L.L.P.

EXPERTS

Certain information appearing in this prospectus regarding the March 31, 2011 estimated quantities of reserves of the Underlying Properties and royalty interests owned by the trust, the future net revenues from those reserves and their present value is based on estimates of the reserves and present values prepared by or derived from estimates prepared by Netherland Sewell & Associates, Inc., independent petroleum engineers.

Certain estimates of SandRidge's proved reserves of oil, natural gas and natural gas liquids that are incorporated by reference in this prospectus were based in part upon engineering reports prepared by independent petroleum engineers Netherland, Sewell & Associates, Inc., DeGolyer and MacNaughton and Lee Keeling and Associates, Inc. These estimates are referred to or incorporated by reference herein in reliance on the authority of such firms as experts in such matters.

The financial statements of SandRidge and management's assessment of the effectiveness of internal control over financial reporting (which is included in Management's Report on Internal Control over Financial Reporting) incorporated in this Prospectus by reference to SandRidge's Annual Report on Form 10-K for the year ended December 31, 2010 have been so incorporated in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The consolidated financial statements for the years ended December 31, 2008 and 2009 of Arena Resources, Inc. ("Arena") included in this prospectus and the effectiveness of Arena's internal control over financial reporting were audited by Hansen, Barnett & Maxwell, P.C., an independent registered public accounting firm, and the consolidated financial statements for the years ended December 31, 2008 and 2009 have been included herein in reliance on their report dated March 1, 2010.

The Statement of Revenues and Direct Operating Expenses of the Arena Properties for the year ended December 31, 2010, included in this prospectus, have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The Statement of Assets and Trust Corpus of the SandRidge Permian Trust as of May 13, 2011, included in this prospectus, has been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

The trust and SandRidge have filed with the SEC a registration statement on Form S-1 and Form S-3 regarding the common units. This prospectus does not contain all of the information found in the registration statement. For further information regarding the trust, SandRidge and the common units offered by this prospectus, you may wish to review the full registration statement, including its exhibits and schedules, filed under the Securities Act. The registration statement of which this prospectus forms a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at 100 F Street, N.E., Washington, D.C. 20549. Copies of the materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC maintains a website on the Internet at http://www.sec.gov. The trust's and SandRidge's registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC's web site.

SandRidge files annual, quarterly and current reports, proxy statements and other information with the SEC) (File No. 001-33784) pursuant to the Exchange Act. SandRidge's SEC filings are available to the public through the SEC's website.

This prospectus includes through incorporation by reference certain of the reports and other information that SandRidge has filed with the SEC. This means that SandRidge is disclosing important information to you by referring to those documents. The information that SandRidge later files with the SEC is incorporated by reference herein and will automatically update and supersede this information. SandRidge hereby incorporates by reference into this prospectus the documents listed below that SandRidge has filed with the SEC:

- SandRidge's Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on February 28, 2011, as amended by SandRidge's Amendment No. 1 on Form 10-K/A to its Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 23, 2011;

- SandRidge's Proxy Statement on Schedule 14A, filed with the SEC on April 25, 2011;

- SandRidge's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on May 9, 2011; and

- SandRidge's Current Reports on Form 8-K filed with the SEC on January 10, 2011, March 3, 2011, March 4, 2011, March 7, 2011, March 18, 2011, April 8, 2011, April 14, 2011, June 8, 2011, June 29, 2011 and August 8, 2011.

SandRidge also hereby incorporates by reference into this prospectus any filings that it makes with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act (excluding any information furnished under Item 2.02 or Item 7.01 on any Current Report on Form 8-K) after the filing of the registration statement to which this prospectus relates and prior to the effectiveness of such registration statement, and all such future filings that it makes with the SEC prior to the later of (a) the closing date of the offering and (b) the completion of the offering of the common units.

In addition, SandRidge incorporates by reference the unaudited pro forma condensed combined statement of operations, giving effect to SandRidge's acquisition of Arena Resources, Inc., for the year ended December 31, 2010, which is filed as an exhibit to SandRidge's Current Report on Form 8-K filed on March 4, 2011.

SandRidge's recent annual, quarterly and current reports, and any amendments thereto, that it files with the SEC are made available, free of charge, over the Internet through SandRidge's website at *http:www.sandridgeenergy.com* as soon as reasonably practicable after SandRidge electronically files them with or furnishes them to the SEC. You may also request copies of any of SandRidge's filings with the SEC, which it will provide at no cost to you, by contacting SandRidge's Investor Relations department at 405-429-5515 or *investors@sdrge.com*. Please note that SandRidge's website and the information contained in and linked to it are not incorporated in this prospectus.

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GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS AND TERMS RELATED TO THE TRUST

In this prospectus the following terms have the meanings specified below.

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

BBtu. Billion British Thermal Units.

BBtu/d. Billion British Thermal Units per day.

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.

Boe/d. Barrels of oil equivalent per day.

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

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

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

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered (a) 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 (b) 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 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 (a) 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, (b) 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, (c) 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 (d) 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.

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

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reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc.

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

MBbls. Thousand barrels of oil or other liquid hydrocarbons.

MBbls/d. Thousand barrels of oil or other liquid hydrocarbons per day.

MBoe. Thousand barrels of oil equivalent.

Mcf. Thousand cubic feet of natural gas.

MMBbls. Million barrels of oil or other liquid hydrocarbons.

MMBoe. Million barrels of oil equivalent.

MMBtu. Million British Thermal Units.

MMcf. Million cubic feet of natural gas.

MMcf/d. MMcf per day.

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

Net revenue interest. A share of production after all burdens, such as royalty and overriding royalty interests, have been deducted from the working interest.

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. Texas regulations 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.

(1) 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.

(2) 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.

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

Proved oil and gas reserves. Those quantities of oil and 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 (a) the area identified by drilling and limited by fluid contacts, if any, and (b) 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 (a) 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 (b) 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.

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PV-10. See "Present value of future net revenues."

Rental tools. A variety of rental tools and equipment, ranging from trash trailers to blow out preventors to sand separators, for use in the oil field.

Reserves. Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible as of a given date, 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 gas or related substances to market, and all permits and financing required to implement the project.

Included Note: 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 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 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 gas regardless of whether such acreage contains proved reserves.

Undeveloped oil and 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.

(a) 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.

(b) 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.

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

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

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SANDRIDGE PERMIAN TRUST

UNAUDITED PRO FORMA FINANCIAL INFORMATION

The following unaudited pro forma statement of assets and trust corpus and unaudited pro forma statements of distributable income for SandRidge Permian Trust (the "Trust") have been prepared to reflect the conveyance of royalty interests in certain oil and natural gas properties located in Andrews County, Texas (the "Underlying Properties") to the Trust by SandRidge Energy, Inc. ("SandRidge"). The Underlying Properties are included within a larger group of oil and natural gas properties owned by SandRidge and acquired in July 2010 as part of its acquisition of Arena Resources, Inc. (the "Arena Properties"). The unaudited pro forma statement of assets and trust corpus presents the beginning statement of assets and trust corpus of the Trust as of March 31, 2011, giving effect to the initial funding of the Trust and the royalty interest conveyance as if those transactions occurred on that date. The unaudited pro forma statements of distributable income present the statements of historical revenue and direct operating expenses of the Arena Properties for the year ended December 31, 2010 and the three-month period ended March 31, 2011, giving effect to the royalty interest conveyance as of the beginning of the period presented, reflecting only pro forma adjustments expected to have a continuing impact on the combined results.

These unaudited pro forma financial statements are for informational purposes only. They do not purport to present the results that would have actually occurred had the royalty interest conveyance been completed on the assumed dates or for the periods presented, or which may be realized in the future.

To produce the pro forma financial information, management made certain estimates. These estimates are based on the most recently available information. To the extent there are significant changes in these amounts, the assumptions and estimates herein could change significantly. The unaudited pro forma statements of distributable income should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in this prospectus and the historical financial statements of the Trust and the Arena Properties, including the related notes, included in this prospectus, and of SandRidge, incorporated by reference from its Annual Report on Form 10-K for the year ended December 31, 2010 and its Quarterly Report on Form 10-Q for the three months ended March 31, 2011.

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SANDRIDGE PERMIAN TRUST

UNAUDITED PRO FORMA STATEMENT OF ASSETS AND TRUST CORPUS

AS OF MARCH 31, 2011

(In Thousands)

	Historical	Adjustments	Pro Forma
Assets			
Cash[a]	$	$ 1	$ 1
Investment in Royalty Interests[b]		657,000	657,000
Total Assets	$	$ 657,001	$ 657,001
Trust Corpus			
Trust Units Issued and Outstanding[a][b]	$	$ 657,001	$ 657,001

The accompanying notes are an integral part of this unaudited pro forma financial information.

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SANDRIDGE PERMIAN TRUST

UNAUDITED PRO FORMA STATEMENT OF DISTRIBUTABLE INCOME

FOR THE YEAR ENDED DECEMBER 31, 2010

(In Thousands, Except Per Unit Data)

	Arena Properties Historical	Excluded from Underlying Properties[c]	Pro Forma Underlying Properties	Royalty Interest Conveyance Pro Forma Adjustments	SandRidge Permian Trust Pro Forma
Oil and natural gas revenues	$ 226,339	$ (144,404)	$ 81,935	$ (16,387)[d]	$ 65,548
Direct operating expenses					
Lease operating expense	28,307	(18,060)	10,247	(10,247)[e]	
Production taxes and other post-production expenses	11,669	(7,445)	4,224	(845)[d]	3,379
Revenues in excess of operating expenses	186,363	(118,899)	67,464	(5,295)	62,169
Less:					
Trust general and administrative expenses				1,300[f][g]	1,300
State income tax				229[h]	229
Distributable income	$ 186,363	$ (118,899)	$ 67,464	$ (6,824)[i]	$ 60,640
Distributable income per unit	n/a	n/a	n/a	n/a	$ 1.16[j]

The accompanying notes are an integral part of this unaudited pro forma financial information.

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SANDRIDGE PERMIAN TRUST

UNAUDITED PRO FORMA STATEMENT OF DISTRIBUTABLE INCOME

(In Thousands, Except Per Unit Data)

	Three Months Ended March 31, 2011				
	Arena Properties Historical	Excluded from Underlying Properties[c]	Pro Forma Underlying Properties	Royalty Interest Conveyance Pro Forma Adjustments	SandRidge Permian Trust Pro Forma
Oil and natural gas revenues	$ 73,089	$ (46,631)	$ 26,458	$ (5,292)[d]	$ 21,166
Direct operating expenses					
Lease operating expense	12,485	(7,965)	4,520	(4,520)[e]	
Production taxes and other post-production expenses	3,729	(2,379)	1,350	(270)[d]	1,080
Revenues in excess of operating expenses	56,875	(36,287)	20,588	(502)	20,086
Less:					
Trust general and administrative expenses				325[f][g]	325
State income tax				74[h]	74
Distributable income	$ 56,875	$ (36,287)	$ 20,588	$ (901)[i]	$ 19,687
Distributable income per unit	n/a	n/a	n/a	n/a	$ 0.37[j]

The accompanying notes are an integral part of this unaudited pro forma financial information.

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SANDRIDGE PERMIAN TRUST

NOTES TO UNAUDITED PRO FORMA FINANCIAL INFORMATION

1. Basis of Presentation

SandRidge Permian Trust (the "Trust") is a Delaware statutory trust formed in May 2011 by SandRidge Energy, Inc. ("SandRidge") to own royalty interests in (a) 509 developed oil and natural gas wells located in Andrews County, Texas (the "Producing Wells") and (b) 888 oil and natural gas development wells to be drilled (the "Development Wells") within an Area of Mutual Interest ("AMI"). The AMI consists of the Grayburg/San Andres formation in the Permian Basin in Andrews County, Texas. SandRidge presently holds approximately 16,800 gross acres (15,900 net acres) in the AMI. SandRidge is obligated to drill, or cause to be drilled, the Development Wells from drilling locations in the AMI on or before March 31, 2016. Except in limited circumstances, until SandRidge has satisfied its drilling obligation, it will not be permitted to drill and complete any wells for its own account within the AMI. Also, a wholly owned subsidiary of SandRidge will grant to the Trust a lien on SandRidge's interest in the AMI (except currently producing wells) in order to secure its drilling obligation to the Trust. The royalty interests will be conveyed from SandRidge's interest in the Producing Wells and the Development Wells in the AMI (the "Underlying Properties"). The royalty interest in the Producing Wells (the "PDP Royalty Interest") entitles the Trust to receive 80% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Producing Wells. The royalty interest in the Development Wells (the "Development Royalty Interest") entitles the Trust to receive 70% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of oil, natural gas and natural gas liquids production attributable to SandRidge's net revenue interest in the Development Wells.

SandRidge will also enter into a derivatives agreement with the Trust to provide the Trust with the effect of specified derivative contracts entered into between SandRidge and third parties. Under the derivatives agreement, SandRidge will pay the Trust amounts it receives from its counterparties, and the Trust will pay SandRidge any amounts that SandRidge is required to pay such counterparties. In addition to the derivatives agreement with SandRidge, the Trust will enter into oil and natural gas derivative contracts directly with unaffiliated counterparties concurrent with the conveyance of the royalty interests. As a party to these contracts, the Trust will receive payments directly from its counterparties, and be required to pay any amounts owed directly to its counterparties. Under the derivatives agreement, as Development Wells are drilled, SandRidge will have the right to assign or novate to the Trust any of the SandRidge-provided derivative contracts, or to replace them with derivative contracts executed by the Trust directly with counterparties, as long as the derivative effects of the assigned or replacement contracts are economically equivalent to the derivative effects of the SandRidge-provided derivative contracts, the counterparties to the assigned or replacement contracts have a corporate credit rating equal to or better than A/A2 as rated by Standard & Poor's or Moody's and the counterparties to the existing derivative contracts approve.

The Trust's receipt of any payments due based on the derivatives agreement depends upon the financial position of SandRidge and SandRidge's hedge contract counterparties. A default by any of the hedge counterparties could reduce the amount of cash available for distributions to the Trust unitholders.

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SANDRIDGE PERMIAN TRUST

NOTES TO UNAUDITED PRO FORMA FINANCIAL INFORMATION (Continued)

1. Basis of Presentation (Continued)

Subsequent to March 31, 2011, SandRidge entered into the following oil swaps, the future benefits of which it intends to convey to the Trust.

Period and Type of Contract	Notional (MBbl) Initial Conveyance	Notional (MBbl) Conveyed with Future Development	Weighted Avg. Fixed Price
August 2011 December 2011			
Price swap contracts	249	166	$ 99.80
January 2012 December 2012			
Price swap contracts	466	687	$ 102.20
January 2013 December 2013			
Price swap contracts	368	921	$ 102.84
January 2014 December 2014			
Price swap contracts	311	1,100	$ 101.75
January 2015 March 2015			
Price swap contracts	71	232	$ 100.90

The Trust's counterparty under the derivatives agreement is SandRidge, whose counterparties will be institutions with corporate credit ratings equal to or better than A/A2. The counterparties to the Trust's direct derivative contracts will also be institutions with corporate credit ratings of at least A/A2. SandRidge will not be required to pay the Trust to the extent of payment defaults by SandRidge's derivative contract counterparties. SandRidge will also have authority, in its role as hedge manager to the Trust, to terminate, restructure or otherwise modify a portion of such contracts in the event SandRidge reasonably determines that the volumes covered by such portion of the contracts exceed, or are expected to exceed, estimated production attributable to the Trust's royalty interests over the periods covered by the contracts. Except in limited circumstances involving the restructuring of an existing derivative contract, the Trust will not have the ability to enter into additional derivative contracts on its own.

The unaudited pro forma statement of assets and trust corpus assumes the Trust formation and conveyance of the royalty interests at March 31, 2011. The unaudited pro forma statements of distributable income assume the conveyance of the royalty interests as of the beginning of the periods presented. The Underlying Properties are included within a larger group of oil and natural gas properties owned by SandRidge and acquired in July 2010 from Arena Resources, Inc. (the "Arena Properties"). The unaudited pro forma statements of distributable income present the historical revenues and direct operating expenses of the Arena Properties and the revenues and direct operating expenses of the Underlying Properties on a pro forma basis reflecting the exclusion of an allocated portion of the revenues and direct operating expenses of the Arena Properties corresponding to the portion of such properties that will not be included in the Underlying Properties. The allocation of these revenues and direct operating expenses for all periods presented was based on the ratio of 2010 annual production from the Underlying Properties to 2010 annual production from the Arena Properties. Additionally, the pro forma statements of distributable income present the revenues and direct operating expenses of the Trust on a pro forma basis reflecting the conveyance of the PDP Royalty Interests from the Underlying Properties by SandRidge to the Trust.

In order to provide support for cash distributions on the common units, SandRidge has agreed to subordinate 13,125,000 of the Trust units it will retain following this offering (the "subordinated units"), which will constitute 25% of the total outstanding Trust units. The subordinated units will be entitled to

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SANDRIDGE PERMIAN TRUST

NOTES TO UNAUDITED PRO FORMA FINANCIAL INFORMATION (Continued)

1. Basis of Presentation (Continued)

receive pro rata distributions from the 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 the common units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on all the common units, including the common units held by SandRidge. Each quarterly subordination threshold is equal to 80% of the target distribution level for the corresponding quarter (each, a "subordination threshold").

In exchange for agreeing to subordinate a majority of its Trust units, and in order to provide additional financial incentive to SandRidge to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, SandRidge will be entitled to receive incentive distributions (the "incentive distributions") equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter is 20% greater than the target distribution for such quarter (each, an "incentive threshold").

The subordinated units will automatically convert into common units on a one-for-one basis and SandRidge's right to receive incentive distributions will terminate, at the end of the fourth full calendar quarter following SandRidge's satisfaction of its drilling obligation with respect to the Development Wells. SandRidge currently expects that it will complete its drilling obligation on or before March 31, 2015 and that, accordingly, the subordinated units will convert into common units on or before March 31, 2016. In the event of delays, SandRidge will have until March 31, 2016 under its contractual obligation to drill all the Development Wells, in which event the subordinated units would convert into common units on or before March 31, 2017. The period during which the subordinated units are outstanding is referred to as the "subordination period."

SandRidge believes that the assumptions used provide a reasonable basis for presenting the effects directly attributable to this transaction.

The unaudited pro forma financial information should be read in conjunction with the Statement of Assets and Trust Corpus for the Trust and the Statements of Revenues and Direct Operating Expenses for the Arena Properties and related notes, respectively, for the periods presented.

2. Trust Accounting Policies

The Unaudited Pro Forma Statements of Distributable Income were derived from the historical accounting records of the Arena Properties.

Income determined in accordance with accounting principles generally accepted in the United States of America ("GAAP") would include all expenses incurred for the period presented. However, the Trust serves as a pass-through entity, with expenses for depletion, interest and income taxes, other than the Texas Franchise Tax to which the Trust is subject, being based upon the status and elections of the Trust unitholders. In addition, the royalty interests will not be burdened by field and lease operating expenses. Thus, the statements purport to show distributable income, defined as income of the Trust available for distribution to the Trust unitholders before application of those unitholders' additional expenses, if any, for depreciation, depletion and amortization, interest and income taxes. The revenues are reflected net of existing royalties and overriding royalties associated with SandRidge's interests and have been reduced by gathering and any other post-production expenses. Actual cash receipts may vary due to timing delays of

SANDRIDGE PERMIAN TRUST

NOTES TO UNAUDITED PRO FORMA FINANCIAL INFORMATION (Continued)

2. Trust Accounting Policies (Continued)

actual cash receipts from the property purchasers and due to wellhead and pipeline volume balancing agreements or practices.

Investment in Royalty Interests will be assessed to determine whether net capitalized cost is impaired whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment is indicated when the net capitalized cost of the Investment in Royalty Interests exceeds undiscounted future net revenues attributable to the proved oil and natural gas reserves of the royalty interests. The Trust will provide a write-down to the extent that the net capitalized costs exceed the fair value of the proved oil and natural gas reserves attributable to the Trust's royalty interests. Any such write-down would be charged directly to trust corpus and would not reduce distributable income.

3. Income Taxes

The Trust is a Delaware statutory trust, which is treated as a partnership for federal income taxes and most state income taxes. As such, no provision for federal income taxes has been made. However, the Trust's activities result in the Trust having nexus in Texas and therefore a filing responsibility for Texas Franchise Tax. Accordingly, a provision for Texas Franchise Tax has been made at an estimated effective rate of .35% of total revenue and is reflected as state income tax on the accompanying pro forma statements.

4. Pro Forma Adjustments

The following adjustments were made in the preparation of the unaudited pro forma financial information:

(a) SandRidge transferred $1,000 to the Trust on May 13, 2011, constituting the initial Trust estate.

(b) Reflects SandRidge's conveyance of the royalty interests to the Trust in exchange for all of the net proceeds of this offering as well as common and subordinated units representing an assumed 43% beneficial interest in the Trust. The Investment in Royalty Interests is recorded at the historical cost of SandRidge which was determined by allocating the historical net book value of SandRidge's full cost pool based on the fair value of the conveyed royalty interests in the Underlying Properties relative to the fair value of SandRidge's total full cost pool.

(c) Adjustment to deduct revenues and direct operating expenses of the Arena Properties corresponding to the portion of those properties that will not comprise part of the Underlying Properties.

(d) Adjustment to deduct revenues, production taxes and other post-production expenses attributable to interest in the Underlying Properties that will be retained by SandRidge.

(e) Historical lease operating expenses are not deducted in determining net revenue attributable to royalty interests or in determining distributable income. Royalty interests, as defined in the conveyance, will bear a pro rata share of the taxes on production and property, if any, and applicable gathering and other post-production expenses related to making the production saleable.

(f) The Trust's general and administrative expenses are estimated at $1,300,000 annually. Such expenses include trustee fees, administrative service fees and costs associated with being a public entity.

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SANDRIDGE PERMIAN TRUST

NOTES TO UNAUDITED PRO FORMA FINANCIAL INFORMATION (Continued)

4. Pro Forma Adjustments (Continued)

(g) The trustee intends to withhold $1,000,000 from the first quarterly distribution to establish a cash reserve to cover Trust administration expenses. The establishment of such reserve has not been reflected in the pro forma statements of distributable income due to its non-recurring nature.

(h) Reflects Texas Franchise Tax applicable to the Trust at an estimated effective rate of .35% of total revenue.

(i) Assumes that no incentive threshold was reached during the period.

(j) Assumes issuance of 52,500,000 Trust units.

5. Pro Forma Supplemental Oil and Natural Gas Reserve and Standardized Measure Information

Information with respect to the oil and natural gas producing activities of the Arena Properties on a historical basis, as well as the Underlying Properties and the Trust's royalty interests in the Underlying Properties on a pro forma basis, is presented in the following tables. The information was derived from reserve reports which were prepared by SandRidge and its independent petroleum engineers in accordance with Accounting Standards Codification ("ASC") Topic 932, Extractive Activities Oil and Gas.

Oil and Natural Gas Reserve Quantities

Proved oil and natural gas reserves are those quantities of oil and natural gas that, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible, based on prices used to estimate reserves, from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time of which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively large major expenditure is required for recompletion.

The following table presents the estimated remaining net proved, proved developed and proved undeveloped oil and natural gas reserves of the Arena Properties on a historical basis, and in the Underlying Properties as well as the Trust's royalty interests in the Underlying Properties on a pro forma basis, all of which properties are located in the continental United States, estimated by SandRidge and its

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SANDRIDGE PERMIAN TRUST

NOTES TO UNAUDITED PRO FORMA FINANCIAL INFORMATION (Continued)

5. Pro Forma Supplemental Oil and Natural Gas Reserve and Standardized Measure Information (Continued)

independent petroleum engineers, and the related summary of changes in estimated quantities of net remaining proved reserves during the year ended December 31, 2010.

	Arena Properties Historical		Excluded from Underlying Properties		Pro Forma Underlying Properties		Royalty Interest Conveyance Pro Forma Adjustments		SandRidge Permian Trust Pro Forma	
	Oil (Bbls)(2)	Gas (Mcf)	Oil (Bbls)(2)	Gas (Mcf)	Oil (Bbls)(2)	Gas (Mcf)	Oil (Bbls)(2)	Gas (Mcf)	Oil (Bbls)(2)	Gas (Mcf)
Proved Reserves										
As of December 31, 2009	59,715,512	57,214,688	(36,617,512)	(35,084,688)	23,098,000	22,130,000	(7,163,000)	(6,863,000)	15,935,000	15,267,000
Revisions of previous estimates	10,100,679	(19,863,724)	(5,927,455)	9,756,943	4,173,224	(10,106,781)	(1,189,325)	3,149,036	2,983,899	(6,957,745)
Acquisitions of new reserves	80,821	26,052	(1,121)	(552)	79,700	25,500	(20,300)	(6,500)	59,400	19,000
Extensions and discoveries(1)	15,641,066	7,261,456	(9,587,966)	(4,451,256)	6,053,100	2,810,200	(2,102,500)	(976,800)	3,950,600	1,833,400
Production	(2,953,381)	(2,288,175)	1,884,257	1,459,856	(1,069,124)	(828,319)	213,825	165,664	(855,299)	(662,655)
As of December 31, 2010	82,584,697	42,350,297	(50,249,797)	(28,319,697)	32,334,900	14,030,600	(10,261,300)	(4,531,600)	22,073,600	9,499,000
Proved developed reserves:										
As of December 31, 2009	21,144,906	28,302,469	(12,961,829)	(17,349,412)	8,183,077	10,953,057	(2,079,287)	(2,783,128)	6,103,790	8,169,929
As of December 31, 2010	23,554,741	14,084,846	(16,469,341)	(11,788,046)	7,085,400	2,296,800	(1,692,000)	(546,600)	5,393,400	1,750,200
Proved undeveloped reserves:										
As of December 31, 2009	38,570,606	28,912,219	(23,655,683)	(17,735,276)	14,914,923	11,176,943	(5,083,713)	(4,079,872)	9,831,210	7,097,071
As of December 31, 2010	59,029,956	28,265,451	(33,780,456)	(16,531,651)	25,249,500	11,733,800	(8,569,300)	(3,985,000)	16,680,200	7,748,800

(1)

Extensions and discoveries for the year ended December 31, 2010 are a result of the successful drilling in the Permian Basin. During 2010, SandRidge and Arena drilled approximately 370 wells, from which a portion of royalty interests conveyed to the Trust will be derived.

(2)
Includes natural gas liquids.

Standardized Measure of Discounted Future Net Cash Flows

Certain information concerning the assumptions used in computing the valuation of proved developed reserves and their inherent limitations are discussed below. SandRidge believes such information is essential for a proper understanding and assessment of the data presented. These assumptions are summarized as follows:

- Pricing is applied based upon 12-month average market prices, using the first-day-of-the-month price for each month, at December 31, 2010, adjusted for fixed or determinable contracts that were in existence at period end. The calculated weighted average per unit prices for the Arena Properties' proved reserves and future net revenues were $68.83 per barrel of oil and $3.14 per Mcf of natural gas.

- Future development and production costs are determined based upon actual cost at period end.

- The standardized measure of discounted future net cash flows includes projections of future abandonment costs at period end.

- Future income tax expenses are computed based upon the estimated effective state income tax rate of .35%. The Trust is not required to pay federal income taxes.

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SANDRIDGE PERMIAN TRUST

NOTES TO UNAUDITED PRO FORMA FINANCIAL INFORMATION (Continued)

5. Pro Forma Supplemental Oil and Natural Gas Reserve and Standardized Measure Information (Continued)

An annual discount factor of 10% is applied to the future net cash flows.

Extensive judgments are involved in estimating the timing of production and the costs that will be incurred throughout the remaining lives of the properties. Accordingly, the estimates of future net cash flows from proved reserves and the present value may be materially different from subsequent actual results. The standardized measure of discounted net cash flows does not purport to present, nor should it be interpreted to present, the fair value of the Trust's royalty interests in the Underlying Properties' oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, and anticipated future changes in prices and costs. The following table presents future net cash flows relating to the Arena Properties on a historical basis, as well as to the Underlying Properties and the Trust's royalty interests in the Underlying Properties on a pro forma basis, based on the standardized measure in ASC Topic 932 (in thousands).

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	December 31, 2010				
	Arena Properties Historical	Excluded From Underlying Properties[a]	Pro Forma Underlying Properties	Royalty Interest Conveyance Pro Forma Adjustments	SandRidge Permian Trust Pro Forma
Future cash inflows from production	$ 5,816,967	$ (3,526,698)	$ 2,290,269	$ (725,971)[b]	$ 1,564,298
Future production costs	(1,525,872)	928,324	(597,548)	484,991[c]	(112,557)
Future development costs[1]	(1,099,678)	630,319	(469,359)	469,359[d]	
Future income taxes				(5,475)[f]	(5,475)
Undiscounted future net cash flows	3,191,417	(1,968,055)	1,223,362	222,904	1,446,266
10% annual discount	(1,807,784)	1,124,037	(683,747)	(7,162)	(690,909)
Standardized measure of discounted future net cash flows	$ 1,383,633	$ (844,018)	$ 539,615	$ 215,742	$ 755,357

(1) Includes future abandonment costs.

Changes in the standardized measure of future net cash flows related to proved oil and gas reserves are as follows for the year ended December 31, 2010 (in thousands).

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SANDRIDGE PERMIAN TRUST

NOTES TO UNAUDITED PRO FORMA FINANCIAL INFORMATION (Continued)

5. Pro Forma Supplemental Oil and Natural Gas Reserve and Standardized Measure Information (Continued)

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS

	Arena Properties Historical	Excluded From Underlying Properties[a]	Pro Forma Underlying Properties	Royalty Interest Conveyance Pro Forma Adjustments	SandRidge Permian Trust Pro Forma
Present value as of December 31, 2009	$ 1,121,358	$ (687,392)	$ 433,966	$ 58,388	$ 492,354
Changes during the period:					
Revenues less production and other costs	(186,363)	118,899	(67,464)	5,295[c]	(62,169)
Net changes in prices, production and other costs	166,080	(101,807)	64,273	(19,035)[c]	45,238
Development costs incurred	193,795	(118,796)	74,999	(74,999)[d]	
Net changes in future development costs	(338,783)	207,674	(131,109)	131,109[d]	
Extensions and discoveries	211,502	(129,016)	82,486	51,852[e]	134,338
Revisions of previous quantity estimates	224,517	(137,629)	86,888	5,833[b]	92,721
Accretion of discount	60,694	(37,205)	23,489	22,758[b]	46,247
Net changes in income taxes				(935)[f]	(935)
Purchases of reserves in place	2,498	(31)	2,467	(391)[b]	2,076
Timing differences and other	(71,665)	41,285	(30,380)	35,867[b]	5,487
Net change for the period	262,275	(156,626)	105,649	157,354	263,003
Present value as of December 31, 2010	$ 1,383,633	$ (844,018)	$ 539,615	$ 215,742	$ 755,357

Adjustments:

(a) Reflects portion attributable to Arena Properties not included in the Underlying Properties.

(b) Reflects amounts attributable to retained interest of SandRidge in the Underlying Properties.

(c) Production costs to which the Trust's interest is not subject and amounts attributable to retained interest of SandRidge in the Underlying Properties.

(d) Development costs to which the Trust's interest is not subject.

(e) Extensions, discoveries and other additions attributable to the retained interest of SandRidge net of 100% of the future development costs and production costs attributable to the Underlying Properties.

(f)

Texas Franchise Tax to which the Trust is subject.

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Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying statement of revenues and direct operating expenses of the Arena Properties, described in Note 1, for the year ended December 31, 2010. This financial statement is the responsibility of SandRidge Energy, Inc.'s management. Our responsibility is to express an opinion on this financial statement based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the statement of revenues and direct operating expenses of the Arena Properties is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the statement of revenues and direct operating expenses of the Arena Properties. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the statement referred to above presents fairly, in all material respects, the revenues and direct operating expenses of the Arena Properties for the year ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

The accompanying statement reflects the revenues and direct operating expenses of the Arena Properties as described in Note 1 to the financial statement and is not intended to be a complete presentation of the financial position, results of operations or cash flows of the Arena Properties.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
May 25, 2011

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ARENA PROPERTIES

STATEMENT OF REVENUES AND DIRECT OPERATING EXPENSES

FOR THE YEAR ENDED DECEMBER 31, 2010

(In Thousands)

Oil and natural gas revenues	$ 226,339
Direct operating expenses	
Lease operating expense	28,307
Production taxes and other post-production expenses	11,669
Total direct operating expenses	39,976
Revenues in excess of operating expenses	$ 186,363

The accompanying notes are an integral part of this financial statement.

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ARENA PROPERTIES

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

(In Thousands)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2011
	(Unaudited)	
Oil and natural gas revenues	$ 51,798	$ 73,089
Direct operating expenses		
Lease operating expense	4,442	12,485
Production taxes and other post-production expenses	2,808	3,729
Total direct operating expenses	7,250	16,214
Revenues in excess of operating expenses	$ 44,548	$ 56,875

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

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ARENA PROPERTIES

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

1. Basis of Presentation

The accompanying statements present the revenues and direct operating expenses for the year ended December 31, 2010 and the three-month periods ended March 31, 2010 and 2011 of working interests in oil and natural gas properties purchased by SandRidge Energy, Inc. ("SandRidge") from Arena Resources, Inc. ("Arena") in July 2010 (the "Arena Properties"). The Arena Properties are located in Oklahoma, Texas, New Mexico and Kansas.

The accompanying statements of revenues and direct operating expenses are presented on the accrual basis of accounting and were derived from the historical accounting records of SandRidge and Arena. Revenues and direct operating expenses relate to SandRidge's and Arena's historical net revenue interest and net working interest, respectively, in the Arena Properties. Oil and natural gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Revenues are reported net of existing overriding and other royalties due to third parties. Direct operating expenses include lease and well repairs, maintenance, utilities, payroll, production taxes, gathering and transportation and other direct operating expenses. The amounts presented represent 100% of SandRidge's interests in the Arena Properties.

During the periods presented, the Arena Properties were not accounted for as a separate division by SandRidge or Arena and therefore certain costs such as depreciation, depletion and amortization, accretion of asset retirement obligation, general and administrative expenses, interest, and corporate income taxes were not allocated to the individual properties. Historical statements reflecting financial position, results of operations and cash flows from operating, investing and financing activities prepared in accordance with generally accepted accounting principles are not presented because the information necessary to prepare such statements for periods prior to SandRidge's acquisition of the Arena Properties is neither readily available on an individual property basis nor practicable to obtain in these circumstances. Financial information for the three-month period ended March 31, 2010 has been presented on a basis consistent with the financial information for the three-month period ended March 31, 2011 in order to provide comparability between periods presented. Accordingly, the statements of revenues and direct operating expenses of the Arena Properties are presented in lieu of the financial statements required under Rule 3-01 and 3-02 of the Securities and Exchange Commission Regulation S-X.

The statements of revenues and direct operating expenses for the three-month periods ended March 31, 2010 and 2011 are unaudited and should be read in conjunction with the financial statement for the year ended December 31, 2010. Such interim financial statements have been prepared on the same basis as the annual financial statement, as stated above. In the opinion of SandRidge, all adjustments, which consist of normal recurring adjustments, necessary to state fairly the information in the unaudited statements have been included.

2. Subsequent Events

Events occurring after December 31, 2010 were evaluated through May 25, 2011 to ensure that any subsequent events that met the criteria for recognition and/or disclosure in this report have been included.

3. Supplemental Oil and Natural Gas Reserve and Standardized Measure Information (Unaudited)

The following oil and natural gas reserve information was prepared by SandRidge based upon information provided by SandRidge and its independent petroleum engineers and is presented in accordance with Accounting Standards Codification ("ASC") Topic 932, Extractive Activities Oil and Gas.

ARENA PROPERTIES

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES (Continued)

3. Supplemental Oil and Natural Gas Reserve and Standardized Measure Information (Unaudited) (Continued)

Oil and Gas Reserve Quantities

Proved oil and natural gas reserves are those quantities of oil and natural gas that, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible, based on prices used to estimate reserves, from a given date forward from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time of which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain. Proved developed reserves are proved reserves expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively large major expenditure is required for recompletion.

The following table presents the estimated remaining net proved, proved developed and proved undeveloped oil and natural gas reserves of the Arena Properties, all of which are located in the continental United States, estimated by SandRidge and its independent petroleum engineers, and the related summary of changes in estimated quantities of net remaining proved reserves during the year ended December 31, 2010. These reserves represent the total proved reserves for the remaining economic life of the Arena Properties and do not represent the reserves that will be owned by the Trust. A table setting forth the reserves that will be owned by the Trust can be found on page F-10.

	Oil (Bbls)[(b)]	Gas (Mcf)
Proved Reserves		
As of December 31, 2009	59,715,512	57,214,688
Revisions of previous estimates	10,100,679	(19,863,724)
Acquisitions of new reserves	80,821	26,052
Extensions and discoveries[(a)]	15,641,066	7,261,456
Production	(2,953,381)	(2,288,175)
As of December 31, 2010	82,584,697	42,350,297
Proved developed reserves		
As of December 31, 2009	21,144,906	28,302,469
As of December 31, 2010	23,554,741	14,084,846
Proved undeveloped reserves		
As of December 31, 2009	38,570,606	28,912,219
As of December 31, 2010	59,029,956	28,265,451

(a) Extensions and discoveries for the year ended December 31, 2010 are a result of the successful drilling in the Permian Basin. During 2010, SandRidge and Arena drilled approximately 370 wells.

(b) Includes natural gas liquids.

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ARENA PROPERTIES

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES (Continued)

3. Supplemental Oil and Natural Gas Reserve and Standardized Measure Information (Unaudited) (Continued)

Standardized Measure of Discounted Future Net Cash Flows

Certain information concerning the assumptions used in computing the valuation of proved developed reserves and their inherent limitations are discussed below. SandRidge believes such information is essential for a proper understanding and assessment of the data presented. These assumptions are summarized as follows:

Pricing is applied based upon 12-month average market prices, using the first-day-of-the-month price for each month, at December 31, 2010, adjusted for fixed or determinable contracts that were in existence at period end. The calculated weighted average per unit prices for the Arena Properties' proved reserves and future net revenues were $68.83 per barrel of oil and $3.14 per Mcf of natural gas.

Future development and production costs are determined based upon actual cost at period end.

The standardized measure of discounted future net cash flows includes projections of future abandonment costs at period end.

Future income taxes are not computed because the Arena Properties are not tax-paying entities.

An annual discount factor of 10% is applied to the future net cash flows.

Extensive judgments are involved in estimating the timing of production and the costs that will be incurred throughout the remaining lives of the properties. Accordingly, the estimates of future net cash flows from proved reserves and the present value may be materially different from subsequent actual results. The standardized measure of discounted net cash flows does not purport to present, nor should it be interpreted to present, the fair value of the Arena Properties' oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, and anticipated future changes in prices and costs. The following table presents future net cash flows relating to the Arena Properties based on the standardized measure in ASC Topic 932 (in thousands).

	December 31, 2010
Future cash inflows from production	$ 5,816,967
Future production costs	(1,525,872)
Future development costs[(a)]	(1,099,678)
Undiscounted future net cash flows	3,191,417
10% annual discount	(1,807,784)
Standardized measure of discounted future net cash flows	$ 1,383,633

(a) Includes future abandonment costs.

ARENA PROPERTIES

NOTES TO STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES (Continued)

3. Supplemental Oil and Natural Gas Reserve and Standardized Measure Information (Unaudited) (Continued)

Changes in the standardized measure of future net cash flows related to proved oil and gas reserves are as follows for the year ended December 31, 2010 (in thousands).

Present value as of December 31, 2009	$ 1,121,358
Changes during the period:	
Revenues less production and other costs	(186,363)
Net changes in prices, production and other costs	166,080
Development costs incurred	193,795
Net changes in future development costs	(338,783)
Extensions and discoveries	211,502
Revisions of previous quantity estimates	224,517
Accretion of discount	60,694
Purchases of reserves in place	2,498
Timing differences and other[a]	(71,665)
Net change for the period	262,275
Present value as of December 31, 2010	$ 1,383,633

(a) The change in timing differences and other are related to revisions in estimated time of production and development.

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Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying statement of assets and trust corpus of SandRidge Permian Trust as of May 13, 2011. This financial statement is the responsibility of the Trust's management. Our responsibility is to express an opinion on this financial statement based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the statement of assets and trust corpus is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the statement of assets and trust corpus. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As described in Note 2, this financial statement was prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, the financial statement referred to above presents fairly, in all material respects, the assets and trust corpus of SandRidge Permian Trust at May 13, 2011, on the basis of accounting described in Note 2.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
May 25, 2011

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SANDRIDGE PERMIAN TRUST

STATEMENT OF ASSETS AND TRUST CORPUS

AS OF MAY 13, 2011

(In Thousands)

Assets	
Cash	$ 1
Total Assets	$ 1
Trust Corpus	
Trust Corpus	$ 1
Total	$ 1

The accompanying notes are an integral part of this financial statement.

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SANDRIDGE PERMIAN TRUST

NOTES TO STATEMENT OF ASSETS AND TRUST CORPUS

1. Organization of the Trust

SandRidge Permian Trust (the "Trust") is a statutory trust formed on May 12, 2011 under the Delaware Statutory Trust Act pursuant to a Trust Agreement (the "Trust Agreement") among and by SandRidge Energy, Inc. ("SandRidge"), as trustor, The Bank of New York Mellon Trust Company, N.A., as Trustee (the "Trustee"), and The Corporation Trust Company, as Delaware Trustee (the "Delaware Trustee").

The Trust was created to acquire and hold royalty interests for the benefit of Trust unitholders pursuant to an agreement between SandRidge, the Trustee and the Delaware Trustee. These royalty interests are interests in underlying properties consisting of SandRidge's interests in specified oil and natural gas properties located in Andrews County, Texas (the "Underlying Properties"). These properties consist of 509 developed oil and natural gas wells at April 1, 2011, (the "Underlying Developed Properties") and 888 oil and natural gas development wells to be drilled ("Underlying Development Properties") in an area of mutual interest ("AMI").

The royalty interests are passive in nature and neither the Trust nor the Trustee has any control over, or responsibility for, costs relating to the operation of the Underlying Properties. After the conveyance of royalty interests, SandRidge will retain interests in each of the Underlying Developed Properties and the Underlying Development properties. The Trust Agreement will provide that the Trust's business activities will generally be limited to owning the royalty interests and entering into the derivative arrangements and activities reasonably related thereto, including activities required or permitted by the terms of the conveyances related to the royalty interests and the derivative arrangements described below.

The Trust will enter into a development agreement with SandRidge that will obligate SandRidge to drill, or cause to be drilled, the equivalent of 888 oil and natural gas development wells (as defined in the agreement) by March 31, 2015. In the event of delays, SandRidge will have until March 31, 2016 to fulfill its drilling obligation. Except in limited circumstances, SandRidge will agree not to drill and complete, or allow another person within its control to drill and complete, any other well in the AMI other than the development wells until SandRidge has fulfilled its drilling obligation. A wholly owned subsidiary of SandRidge will grant to the Trust a lien covering its interest in the AMI (except the Underlying Developed Properties or any other wells already producing and not subject to the royalty interests) in order to secure the estimated amount of the drilling costs for the Trust's interests in the Underlying Development Properties. The amount recoverable under the lien will be reduced and the properties subject to the lien will be released, in each case, as SandRidge fulfills its drilling obligation under the development agreement.

The Trust will enter into an administrative services agreement with SandRidge pursuant to which SandRidge will provide the Trust with certain accounting, tax preparation, bookkeeping and informational services related to the royalty interests, the Trust's derivative contracts and the registration rights agreement. In return for these services, the Trust will pay SandRidge an annual fee of $300,000 in addition to reimbursement for SandRidge's out-of-pocket fees, costs and expenses incurred in connection with the provision of any of the services under the agreement.

SandRidge will also enter into a derivatives agreement with the Trust to provide the Trust with the effect of derivative contracts entered into between SandRidge and third parties. Under the derivatives agreement, SandRidge will pay the Trust amounts it receives from its counterparties, and the Trust will pay SandRidge any amounts that SandRidge is required to pay such counterparties. In addition to the derivatives agreement with SandRidge, the Trust will enter into oil and natural gas derivative contracts directly with unaffiliated counterparties concurrent with the conveyance of the royalty interests. As a party to these contracts, the Trust will receive payment directly from its counterparties, and be required to pay

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SANDRIDGE PERMIAN TRUST

NOTES TO STATEMENT OF ASSETS AND TRUST CORPUS (Continued)

1. Organization of the Trust (Continued)

any amounts owed directly to its counterparties. Under the derivatives agreement, as development wells are drilled, SandRidge will have the right to assign or novate to the Trust any of the SandRidge-provided derivative contracts, or to replace them with derivative contracts executed by the Trust directly with counterparties, as long as the derivative effects of the assigned or replacement contracts are economically equivalent to the derivative effects of the SandRidge-provided derivative contracts, the counterparties to the assigned or replacement contracts have a corporate credit rating equal to or better than A/A2 as rated by Standard & Poor's or Moody's and the counterparties to the existing hedges approve.

The Trust's counterparty under the derivatives agreement is SandRidge, whose counterparties will be institutions with corporate credit ratings equal to or better than A/A2, including Morgan Stanley Capital Group Inc., J. Aron & Company, an affiliate of Goldman, Sachs & Co., and Barclays Bank PLC. The counterparties to the Trust's direct derivative contracts will also be institutions with corporate credit ratings of at least A/A2, including Morgan Stanley Capital Group Inc., J. Aron & Company, an affiliate of Goldman, Sachs & Co., and Barclays Bank PLC. SandRidge will not be required to pay the Trust to the extent of payment defaults by SandRidge's derivative contract counterparties. SandRidge will also have authority, in its role as hedge manager to the Trust, to terminate, restructure or otherwise modify a portion of such contracts in the event SandRidge reasonably determines that the volumes covered by such portion of the contracts exceed, or are expected to exceed, estimated production attributable to the Trust's royalty interests over the periods covered by the contracts. Except in limited circumstances involving the restructuring of an existing derivative contract, the Trust will not have the ability to enter into additional derivative contracts on its own.

The Trust will dissolve and begin to liquidate on March 31, 2031 (the "Termination Date") and will soon thereafter wind up its affairs and terminate. Fifty percent of the royalty interests will automatically revert to SandRidge at the Termination Date, while the remaining royalty interests will be sold and the proceeds will be distributed to the Trust unitholders at the Termination Date or soon thereafter. SandRidge will have a right of first refusal to purchase the remaining fifty percent of the royalty interests at the Termination Date.

2. Significant Accounting Policies

The following is a summary of the significant accounting policies followed by the Trust.

Basis of Accounting. These financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") as the Trust records revenues when received and expenses when paid and may also establish certain cash reserves for contingencies, which would not be accrued in financial statements prepared in accordance with GAAP. Amortization of the Investment in Royalty Interests, calculated on a unit-of-production basis, and any impairments will be charged directly to the trust corpus. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the Securities and Exchange Commission ("SEC") as specified by Staff Accounting Bulletin Topic 12:E, *Financial Statements of Royalty Trusts*.

Most accounting pronouncements apply to entities whose financial statements are prepared in accordance with GAAP, directing such entities to accrue or defer revenues and expenses in a period other than when such revenues were received or expenses were paid. Because the Trust's financial statements are

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SANDRIDGE PERMIAN TRUST

NOTES TO STATEMENT OF ASSETS AND TRUST CORPUS (Continued)

2. Significant Accounting Policies (Continued)

prepared on the modified cash basis as described above, most accounting pronouncements are not applicable to the Trust's financial statements.

Use of Estimates. The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Significant estimates that will impact the Trust's financial statements include estimates of proved oil and natural gas reserves which are used to compute the Trust's amortization of its Investment in Royalty Interests. Actual results could differ from those estimates.

Cash. Cash consists of all highly-liquid instruments with maturities of three months or less at the time of purchase.

Investment in Royalty Interests. The conveyance of the royalty interests to the Trust will be accounted for as a transfer of properties between entities under common control and recorded at the historical cost to SandRidge, which is determined by allocating the historical net book value of SandRidge's full cost pool based on the fair value of the conveyed royalty interests in the Underlying Properties relative to the fair value of SandRidge's full cost pool. The carrying value of the Trust's Investment in Royalty Interests will not necessarily be indicative of the fair value of such royalty interests.

Significant dispositions or abandonment of the Underlying Properties will be charged to Investment in Royalty Interests and the trust corpus. Amortization of the Investment in Royalty Interests will be calculated on a units-of-production basis, whereby the Trust's cost basis is divided by the proved reserves attributable to the royalty interests to derive an amortization rate per reserve unit. Such amortization will not reduce distributable income, rather it will be charged directly to trust corpus. Revisions to estimated future units-of-production will be treated on a prospective basis beginning on the date significant revisions are known.

Investment in Royalty Interests will be assessed to determine whether net capitalized cost is impaired whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment is indicated when the net capitalized costs of the Investment in Royalty Interests exceeds undiscounted future net revenues attributable to the proved oil and natural gas reserves of the Trust's royalty interests. The Trust will provide a write-down to the extent that the net capitalized costs exceed the fair value of the proved oil and natural gas reserves attributable to the Trust's royalty interests. Any such write-down would be charged directly to trust corpus and would not reduce distributable income.

Revenue and Expenses. Revenues will be reflected net of existing royalties and overriding royalties associated with SandRidge's interests and will be reduced by gathering and post-production expenses, production taxes and other allowable costs, such as Trust administrative expenses, in order to determine distributable income. In addition, the royalty interests will not be burdened by field and lease operating expenses.

3. Income Taxes

The Trust is a Delaware statutory trust, which is treated as a partnership for federal income taxes and most state income taxes. The Trust is not required to pay federal income taxes. However, the Trust activities result in the Trust having nexus in Texas and, therefore, make it subject to Texas Franchise Tax.

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SANDRIDGE PERMIAN TRUST

NOTES TO STATEMENT OF ASSETS AND TRUST CORPUS (Continued)

4. Distributions to Unitholders

The Trust will make quarterly cash distributions of the cash received from SandRidge, after deducting trust administrative expenses paid on or about 60 days after the completion of each quarter through (and including) the quarter ending March 31, 2031 (the "Termination Date"). The first quarterly distribution, which will cover April through August 2011, is expected to be made on or about November 30, 2011 to record unitholders as of November 15, 2011. Distributions to unitholders will be recorded when declared.

Upon termination of the Trust, the perpetual royalty interests will be sold, and the net proceeds therefrom will be distributed pro rata to the unitholders soon after the Termination Date. Because payments to the Trust will be generated by depleting assets and the Trust has a finite life with the production from the Underlying Properties diminishing over time, a portion of each distribution will represent a return of original investment to the unitholders.

5. Trust Operating Expenses

Pursuant to the Trust Agreement, if at any time the Trust's cash on hand (including available cash reserves) is not sufficient to pay the Trust's ordinary course administrative expenses as they become due, SandRidge will loan funds to the Trust necessary to pay such expenses. Any funds loaned by SandRidge pursuant to this commitment will be limited to the payment of current accounts payable or other obligations to trade creditors in connection with obtaining goods or services or the payment of other accrued current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness. If SandRidge loans funds pursuant to this commitment, unless SandRidge agrees otherwise, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid. Any such loan will be on an unsecured basis, and the terms of such loan will be substantially the same as those which would be obtained in an arms' length transaction between SandRidge and an unaffiliated third party.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
of Arena Resources, Inc.

We have audited the accompanying consolidated balance sheets of Arena Resources, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations and comprehensive income, stockholders' equity, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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, as well as evaluating the overall financial statement presentation. We believe our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Arena Resources, Inc. and subsidiaries as of December 31, 2009 and 2008, and the consolidated results of their operations and their cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Arena Resources, Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2010 expressed an unqualified opinion thereon.

/s/ HANSEN, BARNETT & MAXWELL, P.C.

Salt Lake City, Utah
March 1, 2010

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ARENA RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

December 31,	2009	2008
ASSETS		
Current Assets		
Cash	$ 63,635,078	$ 58,489,574
Accounts receivable	13,103,483	8,637,308
Joint interest billing receivable	2,392,814	2,836,948
Receivable from oil derivative		2,508,396
Fair value of oil derivative		16,210,478
Prepaid expenses	1,040,513	847,433
Total Current Assets	80,171,888	89,530,137
Property and Equipment		
Oil and gas properties subject to amortization	661,453,134	548,714,235
Oil and gas gathering systems	2,134,876	
Inventory for property development	1,052,538	1,670,067
Drilling rigs	6,694,841	6,899,433
Land, buildings, equipment and leasehold improvements	5,991,983	5,799,045
Total Property and Equipment	677,327,372	563,082,780
Less: Accumulated depreciation, depletion and amortization	(100,428,326)	(60,928,142)
Net Property and Equipment	576,899,046	502,154,638
Total Assets	$ 657,070,934	$ 591,684,775
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$ 17,155,260	$ 12,877,084
Current taxes payable	314,700	
Deferred income taxes		6,046,508
Accrued liabilities	1,101,633	865,955
Total Current Liabilities	18,571,593	19,789,547
Long-Term Liabilities		
Asset retirement liability	7,209,812	5,066,348
Deferred income taxes	108,622,799	84,533,419
Total Long-Term Liabilities	115,832,611	89,599,767
Stockholders' Equity		
Preferred stock $0.001 par value; 10,000,000 shares authorized; no shares issued or outstanding		
	38,694	38,210

Common stock $0.001 par value; 100,000,000 shares authorized; 38,693,963 shares and 38,210,187 shares outstanding, respectively				
Additional paid-in capital		326,990,590		318,701,383
Retained earnings		195,637,446		153,343,267
Accumulated other comprehensive income				10,212,601
Total Stockholders' Equity		522,666,730		482,295,461
Total Liabilities and Stockholders' Equity	$	657,070,934	$	591,684,775

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

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ARENA RESOURCES, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

For the years ended December 31,	2009	2008
Oil and Gas Revenues	$ 126,240,777	$ 208,858,645
Costs and Operating Expenses		
Oil and gas production costs	15,543,461	17,833,144
Oil and gas production taxes	6,455,585	10,518,370
Realized loss (gain) on oil derivative	(14,884,846)	4,275,330
Depreciation, depletion and amortization	38,957,641	29,789,794
Accretion expense	410,926	309,402
General and administrative (which includes $4,649,928 and $6,586,279, respectively, in stock based compensation)	13,453,384	13,557,202
Total Costs and Operating Expenses	59,936,151	76,283,242
Income from Operations	66,304,626	132,575,403
Other Income (Expense)		
Interest income	828,992	1,299,939
Interest expense		(1,145,456)
Net Other Income (Expense)	828,992	154,483
Income Before Provision for Income Taxes	67,133,618	132,729,886
Provision for Income Taxes	(24,839,439)	(49,112,685)
Net Income	$ 42,294,179	$ 83,617,201
Basic Net Income Per Common Share	$ 1.10	$ 2.28
Diluted Net Income Per Common Share	1.09	2.20
Other Comprehensive Income (Loss)		
Net income	$ 42,294,179	$ 83,617,201
Realized loss (gain) on hedge derivative contract settlements reclassified from other comprehensive loss (income), net of tax	(10,222,546)	12,381,887
Change in unrealized deferred hedging gains (losses), net of tax	9,945	632,212
Total Comprehensive Income	$ 32,081,578	$ 96,631,300

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

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ARENA RESOURCES, INC.

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

FOR THE YEARS ENDED DECEMBER 31, 2008 AND 2009

	Common Stock		Additional Paid-in	Deferred	Retained	Accumulated Other Comprehensive	Total Stockholders'
	Shares	Amount	Capital	Compensation	Earnings	Income (Loss)	Equity
Balance December 31, 2007	34,278,779	$ 34,279	$ 190,852,118	$	$ 69,726,066	$ (2,801,498)	$ 257,810,965
Options exercised for cash	1,333,000	1,333	4,689,927				4,691,260
Warrants exercised for cash	97,158	97	446,099				446,196
Issuance of common stock for cash, net	2,501,250	2,501	116,126,960				116,129,461
Expense related to vesting stock based compensation			6,586,279				6,586,279
Gain on change in fair value of oil derivative, net of tax						13,014,099	13,014,099
Net income					83,617,201		83,617,201
Balance December 31, 2008	38,210,187	$ 38,210	$ 318,701,383	$	$ 153,343,267	$ 10,212,601	$ 482,295,461
Options exercised for cash	317,000	317	2,922,123				2,922,440
Warrants exercised for cash	161,550	162	717,161				717,323
Expense related to vesting stock based compensation			4,633,873				4,633,873
Restricted stock grant and vesting	5,226	5	16,050				16,055
Loss on change in fair value of oil derivative, net of tax						(10,212,601)	(10,212,601)
Net income					42,294,179		42,294,179
Balance December 31, 2009	38,693,963	$ 38,694	$ 326,990,590	$	$ 195,637,446	$	$ 522,666,730

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

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ARENA RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,	2009	2008
Cash Flows From Operating Activities		
Net income	$ 42,294,179	$ 83,617,201
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	38,957,641	29,789,794
Provision for income taxes	24,839,439	49,112,685
Stock based compensation	4,649,928	6,586,279
Accretion of asset retirement obligation	410,926	309,402
Changes in assets and liabilities:		
Accounts, joint interest and oil derivative receivable	(1,513,645)	9,835,045
Current and deferred income taxes		(612,480)
Prepaid expenses	(472,478)	(714,040)
Accounts payable and accrued liabilities	4,513,854	(587,238)
Net Cash Provided by Operating Activities	113,679,844	177,336,648
Cash Flows from Investing Activities		
Proceeds from sale of oil and gas properties		296,800
Purchase and development of oil and gas properties	(103,778,202)	(207,022,666)
Purchase of inventory for property development	(6,068,087)	(1,670,067)
Constuction of oil and gas gathering systems	(2,134,876)	
Purchase of buildings, machinery and office equipment	(192,938)	(1,931,517)
Net Cash Used in Investing Activities	(112,174,103)	(210,327,450)
Cash Flows From Financing Activities		
Proceeds from issuance of common stock and warrants, net of offering costs		116,129,461
Proceeds from exercise of warrants, net of offering costs	717,323	446,196
Proceeds from exercise of options	2,922,440	4,691,260
Issuance of notes payable		11,000,000
Payment of notes payable		(46,000,000)
Net Cash Provided by Financing Activities	3,639,763	86,266,917
Net Increase in Cash	5,145,504	53,276,115
Cash at Beginning of Period	58,489,574	5,213,459
Cash at End of Period	$ 63,635,078	$ 58,489,574

For the years ended December 31,	2009	2008
Supplemental Cash Flow Information		
Cash paid for income taxes	$	$ 612,480
Cash paid for interest		1,280,122

Non-Cash Investing and Financing Activities

Asset retirement obligation incurred in property acquisition and development	$ 1,732,538	$ 1,459,534
Depreciation on drilling rigs capitalized as oil and gas properties	542,543	640,977
Use of inventory in property development	6,685,616	

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

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ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations Arena Resources, Inc. (the "Company") is a Nevada corporation that owns interests in oil and gas properties located in Oklahoma, Texas, Kansas and New Mexico. The Company is engaged primarily in the acquisition, exploration and development of oil and gas properties and the production and sale of oil and gas. In 2006, the Company formed two wholly owned subsidiaries, Arena Drilling Co. and ARD Production Company. The accompanying statements of operations and cash flows include the operations of the above subsidiaries from the date of acquisition/formation.

Use of Estimates The preparation of 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, disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Changes in the future estimated oil and natural gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analysis could have a significant impact on the future results of operations.

Consolidation The accompanying consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation.

Concentration of Credit Risk and Accounts Receivable Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of cash and accounts receivable. The Company has cash in excess of federally insured limits at December 31, 2009. The Company places its cash with a high credit quality financial institution.

Substantially all of the Company's accounts receivable is from purchasers of oil and gas. Oil and gas sales are generally unsecured. The Company has not had any significant credit losses in the past and believes its accounts receivable are fully collectable. Accordingly, no allowance for doubtful accounts has been provided. The Company also has a joint interest billing receivable. Joint interest billing receivables are collateralized by the pro rata revenue attributable to the joint interest holders and further by the interest itself.

Cash The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Oil and Gas Properties The Company uses the full cost method of accounting for oil and gas properties. Under this method, all costs associated with acquisition, exploration, and development of oil and gas properties are capitalized. Costs capitalized include acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties and costs of drilling and equipping productive and non-productive wells. Drilling costs include directly related overhead costs. Capitalized costs are categorized either as being subject to amortization or not subject to amortization.

The Company records a liability in the period in which an asset retirement obligation ("ARO") is incurred, in an amount equal to the discounted estimated fair value of the obligation that is capitalized. Thereafter this liability is accreted up to the final retirement cost. An ARO is a future expenditure related to the disposal or other retirement of certain assets. The Company's ARO's relate to future plugging and abandonment expenses of its oil and gas properties and related facilities disposal.

ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

All capitalized costs of oil and gas properties, including the estimated future costs to develop proved reserves and estimated future costs to plug and abandon wells and costs of site restoration, less the estimated salvage value of equipment associated with the oil and gas properties, are amortized on the unit-of-production method using estimates of proved reserves as determined by independent engineers. If the results of an assessment indicate that the properties are impaired, the amount of the impairment is added to the capitalized costs to be amortized. Following is a table showing total depletion and depletion per barrel-of-oil-equivalent rate, by year for the years ended December 31, 2009 and 2008.

	For the Years Ended December	
	2009	2008
Depletion	$ 38,659,746	$ 29,554,184
Depletion rate, per barrel-of-oil-equivalent (BOE)	$ 16.34	$ 12.65

In addition, capitalized costs less accumulated amortization and related deferred income taxes shall not exceed an amount (the full cost ceiling) equal to the sum of:

1) the present value of estimated future net revenues discounted ten percent computed in compliance with SEC guidelines;

2) plus the cost of properties not being amortized;

3) plus the lower of cost or estimated fair value of unproven properties included in the costs being amortized;

4) less income tax effects related to differences between the book and tax basis of the properties.

Drilling Rigs Drilling rigs are valued at historical cost, adjusted for impairment loss less accumulated depreciation. Historical costs include all direct costs associated with the acquisition of drilling rigs and placing them in service. Drilling rigs are depreciated over 10 years but are only depreciated during periods during which they are in use and the depreciation is capitalized as part of oil and gas properties subject to amortization. For the years ended December 31, 2009 and 2008 the Company had depreciation of $542,543 and $640,977, respectively, on the company owned drilling rigs.

Land, Buildings, Equipment and Leasehold Improvements Land, buildings, equipment and leasehold improvements are valued at historical cost, adjusted for impairment loss less accumulated depreciation. Historical costs include all direct costs associated with the acquisition of land, buildings, equipment and leasehold improvements and placing them in service.

Depreciation of buildings and equipment is calculated using the straight-line method based upon the following estimated useful lives:

Buildings and improvements	30 years
Office equipment and software	5-7 years
Machinery and equipment	5-7 years

ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Depreciation expense was $297,895 and $235,609 for the years ended December 31, 2009 and 2008, respectively. An aggregate value of $530,000 has been attributed to the land on which the buildings sit and is not subject to depreciation.

Inventory for Property Development Inventories consist primarily of tubular goods used in development and are stated at the lower of specific cost of each inventory item or market value.

Revenue recognition The Company predominantly derives its revenue from the sale of produced crude oil and natural gas. Revenue is recorded in the month the product is delivered to the purchaser. At the end of each month, the Company estimates the amount of production delivered to purchasers and the price we received. Variances between the Company's estimated revenue and actual payment are recorded in the month the payment is received; however, differences have been insignificant.

Income Taxes Provisions for income taxes are based on taxes payable or refundable for the current year and deferred taxes. Deferred taxes are provided on differences between the tax bases of assets and liabilities and their reported amounts in the financial statements, and tax carry forwards. Deferred tax assets and liabilities are included in the financial statements at currently enacted income tax rates applicable to the period in which the deferred tax assets and liabilities are expected to be realized or settled. As changes in tax laws or rates are enacted, deferred tax assets and liabilities are adjusted through the provision for income taxes.

Earnings Per Share Basic earnings per share is computed by dividing net income by the weighted-average number of common shares outstanding during the year. Diluted earnings per share are calculated to give effect to potentially issuable dilutive common shares.

Major Customers During the year ended December 31, 2009, sales to three customers represented 75%, 13% and 8% of total sales, respectively. At December 31, 2009, these customers made up 74%, 14% and 7% of accounts receivable, respectively. During the year ended December 31, 2008, sales to three customers represented 83%, 8% and 5% of total sales, respectively. At December 31, 2008, these customers made up 84%, 9% and 5% of accounts receivable, respectively. The loss of any of the foregoing customers would not have a material adverse affect on the Company as there is an available market for its crude oil and natural gas production from other purchasers.

Stock-Based Employee Compensation The Company has outstanding stock options and restricted stock grants to directors and employees, which are described more fully in Note 7. The Company accounts for its stock options and restricted stock grants in accordance with generally accepted accounting principles. The generally accepted accounting principles require the recognition of the cost of employee services received in exchange for an award of equity instruments in the financial statements and is measured based on the grant date fair value of the award. The generally accepted accounting principles also requires the stock option compensation expense to be recognized over the period during which an employee is required to provide service in exchange for the award (the vesting period).

Stock-based employee compensation incurred for the years ended December 31, 2009 and 2008 was $4,649,928 and $6,586,279, respectively.

Stock-Based Compensation to Non-Employees The Company accounts for its stock-based compensation issued to non-employees using the fair value method in accordance with generally accepted accounting

ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

principles. Under generally accepted accounting principles, stock-based compensation is determined as either the fair value of the consideration received or the fair value of the equity instruments issued, whichever is more reliably measurable. The measurement date for these issuances is the earlier of the date at which a commitment for performance by the recipient to earn the equity instruments is reached or the date at which the recipient's performance is complete.

Derivative Instruments and Hedging Activities Generally accepted accounting principles have established accounting and reporting standards requiring that derivative instruments (including certain derivative instruments embedded in other contracts) be recorded at fair value and included in the consolidated balance sheet as assets or liabilities. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated as cash flow hedges, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any change in the fair value resulting from ineffectiveness, as defined by generally accepted accounting principles, is recognized immediately in oil and natural gas sales. For derivative instruments designated as fair value hedges, changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Differences between the changes in the fair values of the hedged item and the derivative instrument, if any, represent gains or losses on ineffectiveness and are reflected currently in interest expense. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in fair value of contracts that do not qualify as hedges or are not designated as hedges are also recognized currently in earnings. See Note 10 *Derivative Instruments and Hedging Activities*.

New Accounting Policies *Recent SEC Rule-Making Activity*In December 2008, the SEC announced that it had approved revisions to modernize the oil and gas reserve reporting disclosures. The new disclosure requirements include provisions that:

- Introduce a new definition of oil and gas producing activities. This new definition allows companies to include in their reserve base volumes from unconventional resources. Such unconventional resources include bitumen extracted from oil sands and oil and gas extracted from coal beds and shale formations.

- Report oil and gas reserves using an unweighted average price using the prior 12-month period, based on the closing prices on the first day of each month, rather than year-end prices.

- Permit companies to disclose their probable and possible reserves on a voluntary basis. In the past, proved reserves were the only reserves allowed in the disclosures. We have chosen not to make disclosure under these categories.

- Requires companies to provide additional disclosure regarding the aging of proved undeveloped reserves.

- Permit the use of reliable technologies to determine proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserves volumes.

- Replace the existing "certainty" test for areas beyond one offsetting drilling unit from a productive well with a "reasonable certainty" test.

ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Require additional disclosures regarding the qualifications of the chief technical person who oversees the company's overall reserve estimation process. Additionally, disclosures regarding internal controls over reserve estimation, as well as a report addressing the independence and qualifications of its reserves preparer or auditor will be mandatory.

We adopted the rules effective December 31, 2009.

In August 2009, the FASB issued Accounting Standards Update 2009-5, "Measuring Liabilities at Fair Value" in order to provide further guidance on how to measure the fair value of a liability. The Update clarifies that, in circumstances in which a quoted price in an active market for the identical liability is not available, a reporting entity is required to measure fair value using one or more prescribed techniques. We adopted the new guidance as of October 1, 2009. Adoption of the new guidance had no impact on our financial position or results of operations.

Fair Value Option Under US GAAP for fair value measurements, companies have an option to report selected financial assets and liabilities at fair value. We adopted the new guidance for optional fair value measurements as of January 1, 2008. Adoption of the new guidance had no effect on our financial position or results of operations as we made no elections to report selected financial assets or liabilities at fair value.

Derivative Instruments and Hedging Activities In March 2008, the FASB issued new standards which amended and expanded previous disclosure requirements related to derivative instruments and hedging activities. The new standards require qualitative disclosures about objectives and strategies for using derivative instruments, quantitative disclosures about fair value amounts of derivative instruments and related gains and losses, and disclosures about credit risk-related contingent features in derivative agreements. We adopted the new standards as of January 1, 2009. They provide only for enhanced disclosures, and adoption of the new standards had no impact on our financial position or results of operations. See Note 10 *Derivative Instruments and Hedging Activities*.

Subsequent Events In May 2009, the FASB issued new standards which establish the accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. In particular, the new standards set forth:

- the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements (through the date that the financial statements are issued or are available to be issued);

- the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and

- the disclosures that an entity should make about events or transactions that occurred after the balance sheet date.

We adopted the new standards as of June 30, 2009. We have evaluated subsequent events after the balance sheet date of December 31, 2009 through the time of filing with the SEC on March 1, 2010, which is the date the financial statements were issued.

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ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 1 ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Accounting Standards Codification In June 2009, the FASB established the FASB Accounting Standards Codification (Codification), which officially commenced July 1, 2009, to become the source of authoritative US GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative US GAAP for SEC registrants. Generally, the Codification is not expected to change US GAAP. All other accounting literature excluded from the Codification will be considered nonauthoritative. The Codification is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We adopted the new standards for our quarter ending September 30, 2009. All references to authoritative accounting literature are now referenced in accordance with the Codification.

NOTE 2 EARNINGS PER SHARE INFORMATION

For the years ended December 31,	**2009**	**2008**
Net Income	$ 42,294,179	$ 83,617,201
Basic Weighted-Average Common Shares Outstanding	38,380,284	36,732,000
Effect of dilutive securities		
Warrants	75,924	205,846
Stock options	501,737	986,251
Diluted Weighted-Average Common Shares Outstanding	38,957,945	37,924,097
Basic Income Per Common Share		
Net income	1.10	2.28
Diluted Income Per Common Share		
Net Income	1.09	2.20

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ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 3 OIL AND GAS PRODUCING ACTIVITIES

Set forth below is certain information regarding the aggregate capitalized costs of oil and gas properties and costs incurred by the Company for its oil and gas property acquisitions, development and exploration activities:

Capitalized Costs Relating to Oil and Gas Producing Activities

December 31,	2009	2008
Unproved oil and gas properties	$ 5,642,624	$ 5,642,624
Proved oil and gas properties	655,810,510	543,071,611
Oil and gas gathering systems	2,134,876	
Inventory for property development	1,052,538	1,670,067
Drilling rigs	6,694,841	6,899,433
Land, buildings, equipment and leasehold improvements	5,991,983	5,799,045
Total capitalized costs	677,327,372	563,082,780
Less accumulated depletion, depreciation and amortization	(100,428,326)	(60,928,142)
Net Capitalized Costs	$ 576,899,046	$ 502,154,638

Net Costs Incurred in Oil and Gas Producing Activities

For the Years Ended December 31,	2009	2008
Acquisition of proved properties (net of proceeds from property sale)	3,942,103	16,782,225
Acquisition of unproved properties (net of proceeds from property sale)		
Exploration costs		
Development costs	107,064,257	190,584,617
Total Net Costs Incurred	$ 111,006,360	$ 207,366,842

NOTE 4 NOTES PAYABLE

Notes Payable In June 2009, the Company entered into a new agreement that provides for a credit facility of $150 million with a borrowing base of $75 million with the structure in place to increase that borrowing base an additional $75 million. The new facility has an interest rate grid with a range of LIBOR plus 2.25% to 3.25%, depending upon the Company's level of utilization of the credit facility with the total interest rate to be charged being no less than 4.00%. The Company is required under the terms of the credit facility to maintain a 5-to-1 ratio of income before interest, taxes, depreciation, depletion and amortization to interest expense, maintain a current asset to current liability ratio of 1-to-1 and a rolling four quarter maximum leverage ratio of no more than 2.5-to-1. As of December 31, 2009, the Company was in compliance with all covenants and did not have any amount outstanding under this credit facility.

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ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 5 ASSET RETIREMENT OBLIGATION

A reconciliation of the asset retirement obligation for the years ended December 31, 2008 and 2009 is as follows:

Balance, January 1, 2008	$	3,397,830
Liabilities incurred		1,459,534
Accretion expense		309,402
Liabilities settled		(100,418)
Balance, December 31, 2008	$	5,066,348
Liabilities incurred		1,732,538
Accretion expense		410,926
Balance, December 31, 2009	$	7,209,812

NOTE 6 STOCKHOLDERS' EQUITY

The Company is authorized to issue 100,000,000 common shares, with a par value of $0.001 per share, and 10,000,000 Class "A" convertible preferred shares, with a par value of $0.001 per share.

Preferred Stock There is no preferred stock outstanding.

Common Stock Issued in Offerings In June 2008, the Company issued 2,501,250 shares of common stock, valued at $119,434,688, or $47.75 per share, in a public offering pursuant to a shelf registration statement. Proceeds to the Company, net of offering costs of $3,305,227, totaled $116,129,461.

Common Stock Issued from Warrant Exercises During the year ended December 31, 2008, the Company issued 97,158 shares of common stock from the exercise of warrants. Of these warrants, 33,246 had an exercise price of $4.50 per share, 23,132 had an exercise price of $3.7425 per share and 40,780 had an exercise price of $5.15 per share, for total proceeds of $446,159.

During the year ended December 31, 2009, the Company issued 161,550 shares of common stock from the exercise of warrants. Of these warrants, 42,772 had an exercise price of $3.7425, 83,830 had an exercise price of $4.50 and 34,948 had an exercise price of $5.15, for total proceeds of $717,323.

Common Stock Issued from Option Exercises During the year ended December 31, 2008, the Company issued 1,333,000 shares of common stock from the exercise of options for proceeds of $4,691,260. Of these options, 1,140,000 had an exercise price of $1.85 per share, 60,000 had an exercise price of $2.40 per share, 20,000 had an exercise price of $4.15 per share, 20,000 had an exercise price of $13.70 per share, 40,000 had an exercise price of $19.23 per share, 33,000 had an exercise price of $23.42 per share and 20,000 had an exercise price of $26.96 per share.

During the year ended December 31, 2009, the Company issued 317,000 shares of common stock from the exercise of options for proceeds of $2,922,440. Of these options, 220,000 had an exercise price of $4.15, 20,000 had an exercise price of $10.43, 20,000 had an exercise price of $13.70, 27,000 had an exercise price of $23.42, 20,000 had an exercise price of $26.96 and 10,000 had an exercise price of $35.53.

Common Stock Issued pursuant to Restricted Stock Award Plan On December 17, 2009, the Company issued 5,226 shares of common stock to key personnel. The shares issued are subject to a six month vesting period which ends in June 2010. The shares were valued at $43.10, based on the closing price on the date

ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 6 STOCKHOLDERS' EQUITY (Continued)

the shares were awarded. The expense associated with this issuance will be allocated ratably over the six month vesting period.

Warrants Issued Prior to 2008 the Company issued stock purchase warrants in relation to various offerings. No purchase warrants have been issued in 2008 or 2009. However, through 2009 some of the previously issued warrants remained outstanding. During the year ended December 31, 2009, the balance of the remaining outstanding warrants was exercised.

Stock purchase warrants issued and exercised during the years ended December 31, 2009 and 2008 are summarized as follows:

	2009		2008	
	Warrants	Weighted-Average Exercise Price	Warrants	Weighted-Average Exercise Price
Outstanding at beginning of the year	161,550	$ 4.44	258,708	$ 4.50
Issued				
Expired				
Exercised	(161,550)	4.44	(97,158)	4.59
Outstanding at end of year		$	161,550	$ 4.44

NOTE 7 EMPLOYEE STOCK OPTIONS AND RESTRICTED STOCK AWARD PLAN

In 2003, the Company's Board of Directors and shareholders approved and adopted a non-qualified executive stock option plan, which was subsequently amended by the shareholders. The amendments effectively increased the number of shares available under the plan to 6,000,000. Additionally, in 2009 the shareholders approved the adoption of a restricted stock award plan. Shares granted under the restricted stock award plan come from the same pool of available shares as the option plan. There are 1,294,774 shares eligible for grant, either as options or as restricted stock, at December 31, 2009.

Employee Stock Options Following is a table reflecting the issuances during 2008 and their related exercise prices:

Grant date	# of options	Exercise price
May 7, 2008	50,000	$ 45.68
May 15, 2008	50,000	49.74
July 24, 2008	50,000	41.09
August 18, 2008	50,000	39.02
September 2, 2008	25,000	40.75
	225,000	

No options were granted during 2009.

All granted options vest at the rate of 20% each year over five years beginning one year from the date granted and expire six months after the date of complete vesting. A summary of the status of the stock

ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 7 EMPLOYEE STOCK OPTIONS AND RESTRICTED STOCK AWARD PLAN (Continued)

options as of December 31, 2009 and changes during the years ended December 31, 2009 and 2008 is as follows:

	2009		2008	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of the year	2,252,000	$ 22.12	3,450,000	$ 13.55
Issued			225,000	43.53
Forfeited	(40,000)	41.09	(90,000)	22.73
Exercised	(317,000)	9.22	(1,333,000)	3.52
Outstanding at end of year	1,895,000	$ 23.87	2,252,000	$ 22.12
Exercisable at end of year	705,000	$ 20.96	537,000	$ 13.27
Weighted average fair value of options granted during the year		$		$ 17.52

The Company uses the Black-Scholes option pricing model to calculate the fair-value of each option grant. The expected volatility is based on the historical price volatility of the Company's common stock. We elected to use the simplified method for estimating the expected term as allowed by generally accepted accounting principles for options granted through December 31, 2008. Under the simplified method, the expected term is equal to the midpoint between the vesting period and the contractual term of the stock option. The risk-free interest rate represents the U.S. Treasury bill rate for the expected life of the related stock options. The dividend yield represents the Company's anticipated cash dividend over the expected life of the stock options. The following are the Black-Scholes weighted-average assumptions used for options granted during the year ended December 31, 2008 (no options were granted during 2009):

	2008
Risk free interest rate	3.14%
Expected life	4.25 years
Dividend yield	
Volatility	45%

As of December 31, 2009, there was approximately $4,827,499 of unrecognized compensation cost related to stock options that will be recognized over a weighted average period of 2.07 years. The aggregate intrinsic value of options vested and expected to vest at December 31, 2009 was $32,337,120. The aggregate intrinsic value of options exercisable at December 31, 2009 was $15,714,850. The year end intrinsic values are based on a December 31, 2009 closing price of $43.12.

The 317,000 and 1,333,000 options exercised during 2009 and 2008, respectively, had an aggregate intrinsic value on the date of exercise of 7,963,220 and $44,715,770, respectively.

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ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 7 EMPLOYEE STOCK OPTIONS AND RESTRICTED STOCK AWARD PLAN (Continued)

The following table summarizes information related to the Company's stock options outstanding at December 31, 2009:

	Options Outstanding		
Exercise price	**Number Outstanding**	**Weighted-Average Remaining Contractual Life (in years)**	**Number Exercisable**
4.15	305,000	0.50	200,000
10.425	40,000	1.30	20,000
13.70	40,000	1.95	
18.675	100,000	2.53	40,000
19.23	560,000	2.56	200,000
23.42	140,000	2.84	20,000
26.96	60,000	3.07	
35.53	40,000	3.33	10,000
35.54	50,000	3.35	20,000
37.59	250,000	3.42	100,000
37.85	125,000	3.46	50,000
39.02	50,000	3.85	10,000
40.75	25,000	3.87	5,000
41.09	10,000	4.07	10,000
45.68	50,000	4.13	10,000
49.74	50,000	4.17	10,000
	1,895,000	2.06	705,000

Any excess tax benefits from the exercise of stock options will not be recognized in paid-in capital until the Company is in a current tax paying position. Presently, all of the Company's income taxes are deferred and is only subject to alternative minimum tax. The Company has substantial net operating losses available to carryover to future periods. Accordingly, no excess tax benefits have been recognized for the years ended December 31, 2009 or 2008.

Restricted stock grants On December 17, 2009, the Company granted a total of 5,226 shares of stock under the Restricted Stock Award Plan. The shares were valued based on the market price of the shares on the grant date of $43.10 for an aggregate total of $225,241. These shares vest over a six month period and the Company will record the expense over that period. As of December 31, 2009, the Company showed an expense of $16,055. Unamortized deferred compensation of $209,186 will be amortized over the next six months.

The Restricted Stock Award Plan was approved by the shareholders during 2009, therefore no shares were issued under the plan prior to 2009. Additionally, no shares vested during any of the years 2009 and 2008.

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ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 8 COMMITMENTS

Standby Letters of Credit A commercial bank has issued standby letters of credit on behalf of the Company to the states of Texas, Oklahoma and New Mexico totaling $686,969 to allow the Company to do business in those states. The Company intends to renew the standby letters of credit for as long as the Company does business in those states. No amounts have been drawn under the standby letters of credit.

Operating leases Effective August 20, 2008, the Company entered into a lease agreement for office space in Midland, Texas. The lease is for approximately 1,869 square feet and is for five years commencing November 2008. The Company incurred lease expense of $19,780 and $3,271 for the years ended December 31, 2009 and 2008, respectively. The following table reflects the future minimum lease payments under the operating lease as of December 31, 2009.

Year	Lease Obligation
2010	20,715
2011	21,649
2012	22,584
2013	19,469
	$ 84,417

NOTE 9 INCOME TAXES

At December 31, 2009, the Company calculated alternative minimum income tax of $798,690 of which $314,700 is currently payable, due to a previous overpayment. At December 31, 2008, the Company had no alternative minimum income tax due and had no current tax liability. The provision for income taxes consisted of the following:

Provision for income taxes	2009	2008
Current	$ 4,661,395	$
Minimum tax	798,690	
Benefit of net operating loss	(4,661,395)	
Deferred	24,040,749	49,112,685
	$ 24,839,439	$ 49,112,685

The following is a reconciliation of income taxes computed using the U.S. federal statutory rate to the provision for income taxes:

Rate Reconciliation	2009	2008
Tax at federal statutory rate (34%)	$ 22,825,430	$ 45,128,161
Non-deductible expenses		29,406
State tax, net of federal benefit	2,014,009	4,380,086
Other		(424,968)
	$ 24,839,439	$ 49,112,685

ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 9 INCOME TAXES (Continued)

As of December 31, 2009, the Company had net operating loss carry forwards for federal income tax reporting purposes of approximately $75 million which, if unused, will expire in 2026, 2027 and 2028. The Company has minimum tax credits of $1,765,774 which do not expire.

The net deferred tax liability consisted of the following:

Deferred taxes:	**2009**	**2008**
Deferred tax liabilities		
Current unrealized gain on oil derivative	$	$ 6,046,508
Property and equipment	124,200,047	107,316,108
Total deferred tax liabilities	124,200,047	113,362,616
Deferred tax assets		
Stock-based compensation	5,243,557	3,953,790
Minimum tax credit	1,765,774	967,084
Unrealized loss on oil derivative		
Operating loss and IDC carryforwards	8,567,917	17,861,815
Total deferred tax assets	15,577,248	22,782,689
Net deferred income tax liability	$ 108,622,799	$ 90,579,927

Accounting for Uncertainty in Income Taxes In accordance with generally accepted accounting principles, the Company has analyzed its filing positions in all jurisdictions where it is required to file income tax returns for the open tax years in such jurisdictions. The Company has identified its federal income tax return and its state income tax returns in Texas, New Mexico, Oklahoma and Kansas in which it operates as "major" tax jurisdictions. The Company's federal income tax returns for the years ended December 31, 2006 through 2008 remain subject to examination. The Company's income tax returns in major state income tax jurisdictions remain subject to examination for years ended December 31, 2006 through 2008, with the exception of Texas, which would also include the year ended December 31, 2005. The Company currently believes that all significant filing positions are highly certain and that all of its significant income tax filing positions and deductions would be sustained upon audit. Therefore, the Company has no significant reserves for uncertain tax positions and no adjustments to such reserves were required by generally accepted accounting principles. No interest or penalties have been levied against the Company and none are anticipated, therefore interest or penalty has been included in our provision for income taxes in the consolidated statements of operations.

NOTE 10 DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

Under generally accepted accounting principles, the nature of a derivative instrument must be evaluated to determine if it qualifies for hedge accounting treatment. Instruments qualifying for hedge accounting treatment are recorded as an asset or liability measured at fair value and subsequent changes in fair value are recognized in equity through other comprehensive income, net of related taxes, to the extent the hedge is effective. The Company's derivative instrument qualified for hedge accounting for all periods presented. The change in fair value of the derivative instrument was recorded to other comprehensive income for the years ended December 31, 2008 and 2009. The cash settlements of cash flow hedges are recorded in the operating section of the Company's statement of operations. Instruments not qualifying for

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ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 10 DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES (Continued)

hedge accounting treatment are recorded in the balance sheet at fair value and changes in fair value are recognized on the statement of operations.

The Company's hedges are specifically referenced to NYMEX prices. The effectiveness of hedges is evaluated at the time the contracts are entered into, as well as periodically over the life of the contracts, by analyzing the correlation between NYMEX prices and the posted prices received from the designated production. Through this analysis, the Company is able to determine if a high correlation exists between the prices received for its designated production and the NYMEX prices at which the hedges will be settled. At December 31, 2008 and 2009, the Company's hedge contracts were considered effective cash flow hedges.

The statement of operations includes a realized gain on derivative instruments of $14,884,846 for 2009 and a realized loss on derivative instruments of $4,275,330 for 2008.

As of December 31, 2009, the Company had entered into the following costless collar contracts accounted for as a cash flow hedge:

Commodity	Remaining Period	Volume (Bbls)	Floor	Ceiling
WTI Crude Oil	January 2010 - December 2010	730,000	$ 65.00	$ 93.00
WTI Crude Oil	January 2010 - December 2010	365,000	$ 70.00	$ 92.85

Commodity	Remaining Period	Volume (MMBTU)	Floor	Ceiling
El Paso Permian Gas	January 2010 - December 2010	1,825,000	$ 4.00	$ 7.87

There were no hedges in effect as of December 31, 2009, therefore the Company did not record an asset or a liability. The fair value of the 2010 hedges is zero as of December 31, 2009, as the relative price curve for the index prices used is between the floor and the ceiling.

NOTE 11 FAIR VALUE MEASUREMENTS

Generally accepted accounting principles establish a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The Company's fair value balances are based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

Level 1 Quoted prices in active markets for identical assets or liabilities that the Company has the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The Company does not have any fair value balances classified as Level 1.

Level 2 Inputs other than quoted prices in active markets included in Level 1, that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. The Company's Level 2 items consist of a costless collar.

Level 3 Includes inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimate of the

ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 11 FAIR VALUE MEASUREMENTS (Continued)

assumptions market participants would use in determining fair value. Level 3 would include instruments valued using industry standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value. The Company does not have any fair value balances classified as Level 3.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

The fair value of all hedge instruments was zero as of December 31, 2009, therefore the Company does not have either an asset or a liability recorded in connection with those instruments.

NOTE 12 EMPLOYEES' BENEFIT PLANS

The Company's employees are eligible to participate in a 401(k) plan after attaining the age of 21. Participants may defer up to 100% of eligible compensation. The Company matches participant contributions dollar for dollar up to 6% of participant compensation not exceeding $16,500 per employee ($22,000 for those over 50, choosing to catch-up). For the year ended December 31, 2009 and 2008, the Company made contributions to the plan totaling 290,695 and $311,825, respectively.

NOTE 13 QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly financial information is presented in the following summary:

	2008			
	Three Months Ended			
	March 31	June 30	September 30	December 31
Revenues	$ 45,312,392	$ 62,159,281	$ 68,412,686	$ 32,974,286
Operating Income	29,650,936	39,637,781	42,188,778	21,097,908
Net Income	18,318,395	24,794,349	26,922,966	13,581,491
Basic Net Income Per Share	$ 0.52	$ 0.69	$ 0.71	$ 0.36
Diluted Net Income Per Share	0.51	0.67	0.69	0.35

	2009			
	Three Months Ended			
	March 31	June 30	September 30	December 31
Revenues	$ 20,193,160	$ 27,636,695	$ 36,060,878	$ 42,350,044
Operating Income	9,998,248	22,702,454	18,954,179	14,649,746
Net Income	6,465,449	14,436,065	12,113,026	9,279,639
Basic Net Income Per Share	$ 0.17	$ 0.38	$ 0.32	$ 0.24
Diluted Net Income Per Share	0.17	0.37	0.31	0.24

The net income per share information above will not match the income statement due to rounding.

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ARENA RESOURCES, INC.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 14 SIGNIFICANT FOURTH QUARTER ADJUSTMENTS

There were no material fourth quarter adjustments or accounting changes.

NOTE 15 SUBSEQUENT EVENTS

Subsequent to December 31, 2009, the Company issued a total of 75,000 shares of stock pursuant to the restricted stock award plan. These shares were valued based on the market price of the shares of $45.05 on the date of grant of January 6, 2010. These shares will vest 50% per year for two years and the fair value of these shares will be expensed over that period.

We have evaluated subsequent events after the balance sheet date of December 31, 2009 through the time of filing with the SEC on March 1, 2010, which is the date the financial statements were issued.

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ARENA RESOURCES, INC.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES

(Unaudited)

Results of Operations from Oil and Gas Producing Activities The Company's results of operations from oil and gas producing activities exclude interest expense, gain from change in fair value of put options, and other financing expense. Income taxes are based on statutory tax rates, reflecting allowable deductions.

For the Years Ended December 31,	2009	2008
Oil and gas revenues	$ 126,240,777	$ 208,858,645
Production costs	(15,543,461)	(17,833,144)
Production taxes	(6,455,585)	(10,518,370)
Realized loss on oil derivative	14,884,846	(4,275,330)
Depreciation, depletion, amortization and accretion	(39,368,567)	(30,099,196)
General and administrative (exclusive of corporate overhead)	(3,804,383)	(3,034,525)
Results of operations before income taxes	75,953,627	143,098,080
Provision for income taxes	(28,102,842)	(52,946,290)
Results of Oil and Gas Producing Operations	$ 47,850,785	$ 90,151,790

Recent SEC and FASB Rule-Making Activity In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. See Note 1 Organization and Summary of Significant Accounting Policies New Accounting Policies. We adopted the rules effective December 31, 2009 and the rule changes, including those related to pricing and technology, are included in our reserves estimates. The new rule does not allow for prior-year reserve information to be restated, so all information related to periods prior to 2009 is presented consistent with prior SEC rules for the estimation of proved reserves.

In addition, in January 2010 the FASB issued Accounting Standards Update 2010-03, "Oil and Gas Reserve Estimation and Disclosures", to provide consistency with the SEC rules. See Note 1 Organization and Summary of Significant Accounting Policies New Accounting Policies.

Reserve Quantities Information The following estimates of proved and proved developed reserve quantities and related standardized measure of discounted net cash flow are estimates only, and do not purport to reflect realizable values or fair market values of the Company's reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, these estimates are expected to change as future information becomes available. All of the Company's reserves are located in the United States of America.

Proved reserves are estimated reserves of crude oil (including condensate and natural gas liquids) 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. Proved developed reserves are those expected to be recovered through existing wells, equipment and methods.

The standardized measure of discounted future net cash flows is computed by applying the price according to the SEC guidelines for oil and gas to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expenses (based on year-end statutory tax

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ARENA RESOURCES, INC.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (Continued)

(Unaudited)

rates) to be incurred on pretax net cash flows less tax basis of the properties and available credits, and assuming continuation of existing economic conditions. The estimated future net cash flows are then discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows.

	2009		2008	
For the Years Ended December 31,	**Oil(1)**	**Gas(1)**	**Oil(1)**	**Gas(1)**
Proved Developed and Undeveloped Reserves				
Beginning of year	55,845,257	58,804,662	47,413,322	48,074,962
Purchases of minerals in place	1,589,141	2,791,611	3,638,095	2,364,908
Improved recovery and extensions	14,360,492	13,605,184	9,547,981	11,391,853
Production	(2,004,498)	(2,172,790)	(2,018,335)	(1,911,713)
Revision of previous estimate	(10,074,880)	(15,813,979)	(2,735,806)	(1,115,348)
End of year	59,715,512	57,214,688	55,845,257	58,804,662
Proved Developed at end of year	21,144,906	28,302,469	20,231,477	28,659,033

(1) Oil reserves are stated in barrels; gas reserves are stated in thousand cubic feet.

December 31,	**2009**	**2008**
Future cash flows	$ 3,721,873,750	$ 2,391,888,946
Future production costs	(902,963,847)	(716,121,604)
Future development costs	(543,022,875)	(330,672,457)
Future income taxes	(746,548,080)	(394,800,287)
Future net cash flows	1,529,338,948	950,294,598
10% annual discount for estimated timing of cash flows	(775,105,191)	(489,607,688)
Standardized Measure of Discounted Cash Flows	$ 754,233,757	$ 460,686,910

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ARENA RESOURCES, INC.

SUPPLEMENTAL INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES (Continued)

(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows

	2009	2008
Beginning of the year	$ 460,686,910	$ 1,276,166,354
Purchase of minerals in place	28,329,307	41,597,736
Extensions, discoveries and improved recovery, less related costs	253,485,559	129,110,323
Development costs incurred during the year	107,237,470	190,631,820
Sales of oil and gas produced, net of production costs	(110,697,316)	(190,374,853)
Accretion of discount	48,058,341	131,684,244
Net changes in price and production costs	619,543,318	(1,526,963,575)
Net change in estimated future development costs	6,550,757	(22,637,628)
Revision of previous quantity estimates	(447,110,784)	293,723,576
Revision of estimated timing of cash flows	(35,543,586)	(409,158,356)
Net change in income taxes	(176,306,219)	546,907,269
End of the Year	$ 754,233,757	$ 460,686,910

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ANNEX A

May 23, 2011

Mr. Rodney Johnson
SandRidge Energy, Inc.
123 Robert S. Kerr Avenue
Oklahoma City, Oklahoma 73102

Dear Mr. Johnson:

In accordance with your request, we have estimated the proved reserves and future revenue, as of March 31, 2011, to the SandRidge Energy, Inc. (SandRidge) interest in certain oil and gas properties located in Texas and referred to herein as the "Arena properties". It is our understanding that the proved reserves estimated in this report constitute approximately 7 percent of all proved reserves owned by SandRidge. A proposed royalty interest in such reserves is to be conveyed later this year to SandRidge Permian Trust with an effective date of April 1, 2011. As requested, the proposed royalty interest is included in the SandRidge interest in this report. This is an update of our report dated February 10, 2011, which sets forth our estimates of reserves and future revenue to the SandRidge interest as of December 31, 2010. For the purposes of this report, projections for wells that have been drilled since the original report have been reviewed and updated. Proved undeveloped projections have been adjusted based on additional analog performance data and rescheduled in accordance with SandRidge's updated drilling schedule. The remaining projections have been "rolled forward" from our estimates as of December 31, 2010. We completed our evaluation on May 23, 2011. The estimates in this report have been prepared in accordance with the definitions and guidelines of the U.S. Securities and Exchange Commission (SEC) and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas, except that per-well overhead expenses are excluded for operated properties and future income taxes are excluded for all properties. Definitions are presented immediately following this letter. This report has been prepared for SandRidge's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the SandRidge interest in the Arena properties, as of March 31, 2011, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	6,996.5	1,732.8	351,841.9	198,325.5
Proved Developed Non-Producing	585.0	135.6	29,602.2	14,992.1
Proved Undeveloped	23,062.7	5,346.2	946,290.3	367,436.3
Total Proved	30,644.2	7,214.6	1,327,734.4	580,753.9

The oil reserves shown include crude oil, condensate, and natural gas liquids. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

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The estimates shown in this report are for proved reserves. No study was made to determine whether probable or possible reserves might be established for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Future gross revenue to the SandRidge interest is prior to deducting state production taxes and ad valorem taxes. Future net revenue is after deductions for these taxes, future capital costs, operating expenses, and abandonment costs but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability. Our estimates of future net revenue do not include any salvage value for the lease and well equipment but do include SandRidge's estimates of the costs to abandon the wells and production facilities.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period April 2010 through March 2011. For oil volumes, the average West Texas Intermediate posted price of $80.04 per barrel is adjusted for quality, transportation fees, and a regional price differential. For gas volumes, the average Henry Hub Gas Daily price of $4.102 per MMBTU is adjusted for energy content, transportation fees, and a regional price differential. The adjusted oil and gas prices of $79.33 per barrel and $3.002 per MCF are held constant throughout the lives of the properties.

Lease and well operating costs used in this report are based on operating expense records of SandRidge. For nonoperated properties, these costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. As requested, lease and well operating costs for the operated properties include only direct lease- and field-level costs. For all properties, headquarters general and administrative overhead expenses of SandRidge are not included. Lease and well operating costs are held constant throughout the lives of the properties. Capital costs are included as required for workovers, new development wells, and production equipment. The future capital costs are held constant to the date of expenditure.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the SandRidge interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on SandRidge receiving its share of estimated future gross gas production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

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For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and guidelines. A substantial portion of these reserves are for undeveloped locations and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from SandRidge and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-002699

By: /s/ C.H. (SCOTT) REES III

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ DAVID T. MILLER

David T. Miller, P.E. 96134
Vice President

Date Signed: May 23, 2011

By: /s/ JAY P. MITCHELL

Jay P. Mitchell, P.G. 1649
Vice President

Date Signed: May 23, 2011

DTM:AMB

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is 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.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and 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.

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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *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 geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C)

The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii)

Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(20) *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.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and 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 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) 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.

(ii)

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) 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.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) 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

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) 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.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, 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 gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): 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).

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DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*

b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*

b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*

c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*

d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are 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 shall be 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 can be 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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be 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, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

May 24, 2011

Mr. Rodney Johnson
SandRidge Energy, Inc.
123 Robert S. Kerr Avenue
Oklahoma City, Oklahoma 73102

Dear Mr. Johnson:

In accordance with your request, we have estimated the proved reserves and future revenue, as of March 31, 2011, to the proposed royalty interest to be owned by SandRidge Permian Trust (SRPT) in certain oil and gas properties located in Texas and referred to herein as the "Arena properties". It is our understanding that a proposed royalty interest currently owned by SandRidge Energy, Inc. (SandRidge) will be conveyed later this year to SRPT with an effective date of April 1, 2011, and that the proved reserves estimated in this report constitute all of the proved reserves to be owned by SRPT. This is an update of our report dated February 10, 2011, which sets forth our estimates of reserves and future revenue to the SandRidge interest as of December 31, 2010. For the purposes of this report, projections for wells that have been drilled since the original report have been reviewed and updated. Proved undeveloped projections have been adjusted based on additional analog performance data and rescheduled in accordance with SandRidge's updated drilling schedule. The remaining projections have been "rolled forward" from our estimates as of December 31, 2010. We completed our evaluation on May 24, 2011. The estimates in this report have been prepared in accordance with the definitions and guidelines of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for SRPT's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the SRPT interest in the Arena properties, as of March 31, 2011, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	**Oil (MBBL)**	**Gas (MMCF)**	**Total**	**Present Worth at 10%**
Proved Developed Producing	5,126.8	1,270.8	362,637.1	196,278.1
Proved Developed Non-Producing	450.0	104.3	31,901.4	17,435.1
Proved Undeveloped	15,400.5	3,570.1	1,091,881.6	555,778.3
Total Proved	20,977.4	4,945.2	1,486,420.1	769,491.5

Totals may not add because of rounding.

The oil reserves shown include crude oil, condensate, and natural gas liquids. Oil volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. No study was made to determine whether probable or possible reserves might be established for these properties. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Future gross revenue to the SRPT proposed royalty interest is prior to deducting state production taxes and ad valorem taxes. Future net revenue is after deductions for these taxes but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. Since SRPT would own a royalty interest rather than a working interest in these properties, it would not incur any costs due to abandonment or possible environmental liability, nor would it realize any salvage value for the lease and well equipment.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period April 2010 through March 2011. For oil volumes, the average West Texas Intermediate posted price of $80.04 per barrel is adjusted for quality, transportation fees, and a regional price differential. For gas volumes, the average Henry Hub Gas Daily price of $4.102 per MMBTU is adjusted for energy content, transportation fees, and a regional price differential. The adjusted oil and gas prices of $79.33 per barrel and $3.002 per MCF are held constant throughout the lives of the properties.

Because SRPT would own no working interest in these properties, lease and well operating costs would not be incurred. However, estimated lease and well operating costs have been used in the determination of the economic limits for the properties. Lease and well operating costs used in this report are based on operating expense records of SandRidge and are held constant throughout the lives of the properties. Capital costs have been included to determine whether workovers, new development wells, and production equipment requirements are economic. The future capital costs are held constant to the date of expenditure.

We have made no investigation of potential gas volume and value imbalances resulting from overdelivery or underdelivery to the SRPT proposed royalty interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on SRPT receiving its proposed royalty interest share of estimated future gross gas production.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred by the working interest owners in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis and analogy, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and guidelines. A substantial portion of these reserves are for undeveloped locations and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from SandRidge and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting geoscience, performance, and work data are on file in our office. The titles to the properties have not been examined by NSAI, nor has the actual degree or type of interest owned been independently confirmed. The technical persons responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-002699

By: /s/ C.H. (SCOTT) REES III

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ DAVID T. MILLER

David T. Miller, P.E. 96134
Vice President

Date Signed: May 24, 2011

By: /s/ JAY P. MITCHELL

Jay P. Mitchell, P.G. 1649
Vice President

Date Signed: May 24, 2011

DTM:AMB

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is 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.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and 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.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Supplemental definitions from the 2007 Petroleum Resources Management System:

Developed Producing Reserves Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *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 geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(1) Lifting the oil and gas to the surface; and

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(2) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iv)

The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v)

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi)

Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i)

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii)

Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii)

Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv)

See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(20) *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.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and 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 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) 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.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) 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.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) 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

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) 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.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, 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 gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): 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).

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas:

932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*

b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.

932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*

b. *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.*

c. *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.*

d. *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.*

e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*

f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

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(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are 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 shall be 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 can be 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.

From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):

Although several types of projects such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.

Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:

- *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
- *The company's historical record at completing development of comparable long-term projects;*
- *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
- *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*

DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).

(iii) Under no circumstances shall estimates for undeveloped reserves be 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, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

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ANNEX B

Quarterly Target Distributions

Quarter Ending	Subordination Threshold(1)	Target Cash Distribution	Incentive Threshold(1)	Quarter Ending	Target Cash Distribution
September 30, 2011(2)	$ .53	$ .66	$ .79	September 30, 2021	.43
December 31, 2011	.39	.49	.59	December 31, 2021	.42
March 31, 2012	.42	.53	.63	March 31, 2022	.41
June 30, 2012	.44	.55	.66	June 30, 2022	.40
September 30, 2012	.47	.58	.70	September 30, 2022	.39
December 31, 2012	.49	.62	.74	December 31, 2022	.38
March 31, 2013	.51	.64	.77	March 31, 2023	.37
June 30, 2013	.53	.66	.80	June 30, 2023	.37
September 30, 2013	.56	.70	.84	September 30, 2023	.36
December 31, 2013	.58	.73	.87	December 31, 2023	.35
March 31, 2014	.61	.76	.91	March 31, 2024	.34
June 30, 2014	.63	.79	.95	June 30, 2024	.33
September 30, 2014	.65	.82	.98	September 30, 2024	.32
December 31, 2014	.66	.82	.98	December 31, 2024	.32
March 31, 2015	.64	.80	.96	March 31, 2025	.31
June 30, 2015	.61	.77	.92	June 30, 2025	.30
September 30, 2015	.56	.70	.85	September 30, 2025	.29
December 31, 2015	.54	.68	.81	December 31, 2025	.29
March 31, 2016	.53	.67	.80	March 31, 2026	.28
June 30, 2016	.52	.65	.78	June 30, 2026	.27
September 30, 2016	.51	.64	.77	September 30, 2026	.27
December 31, 2016	.50	.63	.75	December 31, 2026	.26
March 31, 2017	.49	.61	.74	March 31, 2027	.25
June 30, 2017		.60		June 30, 2027	.25
September 30, 2017		.59		September 30, 2027	.24
December 31, 2017		.58		December 31, 2027	.24
March 31, 2018		.57		March 31, 2028	.23
June 30, 2018		.56		June 30, 2028	.23
September 30, 2018		.55		September 30, 2028	.22
December 31, 2018		.54		December 31, 2028	.22
March 31, 2019		.53		March 31, 2029	.21
June 30, 2019		.52		June 30, 2029	.20
September 30, 2019		.51		September 30, 2029	.20
December 31, 2019		.51		December 31, 2029	.20
March 31, 2020		.50		March 31, 2030	.19
June 30, 2020		.49		June 30, 2030	.19
September 30, 2020		.48		September 30, 2030	.18
December 31, 2020		.46		December 31, 2030	.18
March 31, 2021		.45		March 31, 2031	.17
June 30, 2021		.44		Remaining	1.63

(1) For each quarter, the Subordination Threshold equals 80% of the Target Cash Distribution, and the Incentive Threshold equals 120% of the Target Cash Distribution.

(2) Includes proceeds attributable to the first five months of production from April 1, 2011 to August 31, 2011.

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SandRidge Permian Trust