CHESAPEAKE ENERGY CORP
Form S-1
July 07, 2011
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As filed with the Securities and Exchange Commission on July 7, 2011

Registration No. 333-

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

FORM S-1
Chesapeake Granite Wash Trust
(Exact name of co-registrant as specified in its charter)
Delaware
(State or other jurisdiction of incorporation or organization)
1311
(Primary Standard Industrial Classification Code Number)
45-6355635
(I.R.S. Employer Identification No.)
919 Congress Avenue, Suite 500

Austin, Texas 78701

(512) 236-6599

FORM S-3
Chesapeake Energy Corporation
(Exact name of co-registrant as specified in its charter)
Oklahoma
(State or other jurisdiction of incorporation or organization)
1311
(Primary Standard Industrial Classification Code Number)
73-1395733
(I.R.S. Employer Identification No.)
6100 North Western Avenue

Oklahoma City, Oklahoma 73118

(405) 848-8000

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)	*(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)*
The Bank of New York Mellon Trust Company, N.A. **919 Congress Avenue, Suite 500** **Austin, Texas 78701** **(512) 236-6599** **Attention: Michael J. Ulrich**	**Jennifer M. Grigsby** **Senior Vice President, Treasurer** **and Corporate Secretary** **6100 North Western Avenue** **Oklahoma City, Oklahoma 73118** **(405) 848-8000**
(Name, address, including zip code, and telephone number, including area code, of agent for service)	*(Name, address, including zip code, and telephone number, including area code, of agent for service)*

Copies to:

Michael S. Telle **Bracewell & Giuliani LLP** **711 Louisiana Street, Suite 2300** **Houston, Texas 77002-2770** **(713) 221-1327** **(713) 221-2113 (fax)**	**Joshua Davidson** **Baker Botts L.L.P.** **One Shell Plaza** **910 Louisiana Street** **Houston, Texas 77002-4995** **(713) 229-1234** **(713) 229-1522 (fax)**

Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box: ¨

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Chesapeake Granite Wash Trust

Large accelerated filer	¨		Accelerated filer	¨
Non-accelerated filer	x	(Do not check if a smaller reporting company)	Smaller reporting company	¨

Chesapeake Energy Corporation

Large accelerated filer	x		Accelerated filer	¨
Non-accelerated filer	¨	(Do not check if a smaller reporting company)	Smaller reporting company	¨

Calculation of Registration Fee

Title of Each Class of Securities to be Registered	**Amount to be Registered**(1)	**Proposed Maximum Offering Price Per Unit**	**Proposed Maximum Aggregate Offering Price**(1)(2)	**Amount of Registration Fee**
Common Units representing Beneficial Interests in Chesapeake Granite Wash Trust	29,181,250	$20.00	$583,625,000	$67,759

(1) Includes trust units issuable upon exercise of the underwriters over-allotment option.
(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o).

The Registrants hereby amend this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrants shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act, or until this Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities, and we are not soliciting an offer to buy these securities, in any state where the offer or sale is not permitted.

PROSPECTUS (Subject to Completion)

Issued July 7, 2011

25,375,000 Common Units

Chesapeake Granite Wash Trust

REPRESENTING BENEFICIAL INTERESTS

This is an initial public offering of common units representing beneficial interests in Chesapeake Granite Wash Trust. The trust is selling all of the common units offered hereby. Chesapeake Energy Corporation (Chesapeake) will convey to the trust certain royalty interests in exchange for common and subordinated units collectively representing a 50% beneficial interest in the trust (without giving effect to the exercise of the underwriters over-allotment option), as well as all of the net proceeds of this offering.

Prior to this offering, there has been no public market for the common units. Chesapeake anticipates that the initial public offering price will be between $ and $ per common unit. The trust intends to apply to have the common units approved for listing on the New York Stock Exchange under the symbol CHKR.

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

The Trust. *The trust will own term and perpetual royalty interests in oil, natural gas and natural gas liquids properties leased by Chesapeake in the Colony Granite Wash play, located in Washita County, Oklahoma. These royalty interests will entitle the trust to receive, after the deduction of post-production expenses and taxes, (a) 90% of the proceeds attributable to Chesapeake s net revenue interest in the sale of production from 60 horizontal producing wells and (b) 50% of the proceeds attributable to Chesapeake s net revenue interest in the sale of production from 122 horizontal development wells to be drilled within an Area of Mutual Interest consisting of approximately 45,400 gross acres (28,700 net acres) held by Chesapeake. The number of wells required to be drilled may increase or decrease in proportion to Chesapeake s actual net revenue interest in each well and other factors described herein. The trust will not be responsible for any costs related to the drilling of these 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 Chesapeake s sale of oil, natural gas and natural gas liquids from properties subject to the royalty interests to be held by the trust. The amount of the distributions will be impacted by oil and natural gas hedges to which the trust will be a party.*

Ownership of Trust Units by Chesapeake. *After the completion of this offering (without giving effect to the exercise of the underwriters over-allotment option), Chesapeake will own 12,687,500 common units and 12,687,500 subordinated units, together representing 50% of all outstanding trust units. If the underwriters exercise their over-allotment option in full, Chesapeake will own 8,881,250 common units and 12,687,500 subordinated units, together representing 42.5% of the total trust units outstanding.*

Incentive Distributions and Subordinated Units. *Chesapeake will be entitled to receive incentive distributions equal to 50% of the amount, if any, by which the cash available for distribution on all of the trust units in any quarter during the subordination period described herein exceeds certain target distribution levels by more than 20%. Trust unitholders, including Chesapeake, will be entitled to receive the remaining 50% of such excess amount on a pro rata basis. A portion of the trust units owned by Chesapeake will be subordinated units and will not be entitled to receive distributions to the extent necessary to support specified distribution levels on the common units. The subordinated units will convert into common units following satisfaction of Chesapeake s drilling obligation. Please see Target Distributions and Subordination and Incentive Thresholds.*

Investing in the common units involves a high degree of risk. See "Risk Factors" beginning on page 20.

PRICE $ A COMMON UNIT

	Price to Public	Underwriting Discounts and Commissions(1)	Proceeds to Trust(2)
Per Common Unit	$	$	$
Total	$	$	$

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

(2) The trust will deliver all of the proceeds it receives in this offering to a wholly owned subsidiary of Chesapeake.

The trust has granted the underwriters the right to purchase up to an additional 3,806,250 common units to cover over-allotments.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of 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 , 2011.

MORGAN STANLEY *RAYMOND JAMES*

, 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 , 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 Chesapeake 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 unless otherwise specified herein. The trust s and Chesapeake 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, the summary reserve reports and the financial statements and notes to those statements. Definitions for certain 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. Ryder Scott Company, L.P., referred to in this prospectus as Ryder Scott, an independent engineering firm, provided the estimates of proved oil and natural gas reserves as of March 31, 2011 included in this prospectus. These estimates are contained in summaries prepared by Ryder Scott of its reserve reports for (a) the Underlying Properties held by Chesapeake and (b) the royalty interests to be held by the trust. These reports are included as Annex A to this prospectus and are referred to in this prospectus as the reserve reports. References to Chesapeake in this prospectus are to Chesapeake Energy Corporation and, where the context requires, its subsidiaries. The royalty interests to be held by the trust are sometimes referred to herein as the trust properties. Unless otherwise indicated, all information in this prospectus assumes an initial public offering price of $ per common unit and no exercise of the underwriters over-allotment option.

Chesapeake Granite Wash Trust

Chesapeake Granite Wash Trust is a Delaware statutory trust formed in June 2011 to own (a) royalty interests to be conveyed to the trust by Chesapeake in 60 horizontal wells producing from the Colony Granite Wash play located in Washita County in western Oklahoma (the Producing Wells), and (b) royalty interests in 122 horizontal development wells (as described in The Trust Development Agreement and Drilling Support Lien) to be drilled exclusively in the Colony Granite Wash (the Development Wells) on properties within an Area of Mutual Interest, or AMI. The AMI is limited to only the Colony Granite Wash formation and is depicted by the area identified in the inside front cover of this prospectus where Chesapeake presently holds approximately 45,400 gross acres (28,700 net acres). The Colony Granite Wash is a formation encountered at depths between approximately 11,500 feet and 13,000 feet that lies between the top of the Des Moines formation (or top of Colony Granite Wash A) and the top of the Prue formation (or base of Colony Granite Wash C). Chesapeake intends to drill, or cause to be drilled, the Development Wells from proved undeveloped (PUD) drilling locations in the AMI by March 31, 2015 and is obligated to complete such drilling by March 31, 2016.

The royalty interests will be conveyed from Chesapeake s interest in the Producing Wells and the Development Wells (the Underlying Properties) effective as of April 1, 2011. The royalty interest in the Producing Wells (the PDP Royalty Interest) entitles the trust to receive 90% of the proceeds (exclusive of any production or development costs but after deducting post-production expenses and any applicable taxes) from the sale of production of oil, natural gas and natural gas liquids attributable to Chesapeake s net revenue interest in the Producing Wells. The royalty interest in the Development Wells (the Development Royalty Interest) entitles the trust to receive 50% of the proceeds (exclusive of any production or development costs but after deducting post-production expenses and any applicable taxes) from the sale of oil, natural gas and natural gas liquids production attributable to Chesapeake 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 43.2 mmboe (47.0% oil and natural gas liquids by volume). This amount includes 16.6 mmboe attributable to the PDP Royalty Interest and 26.6 mmboe attributable to the Development Royalty Interest.

Generally, 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 (90% for the Producing Wells and 50% for the Development Wells) multiplied by (b) Chesapeake s net revenue interest in the well. Chesapeake on average owns a 54.3% net revenue interest in the Producing

Wells. Therefore, the trust will have an average 48.8% net revenue interest in the Producing Wells. Chesapeake on average owns a

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51.2% net revenue interest in the properties on which it expects to drill the Development Wells, and based on this net revenue interest, the trust would have an average 25.6% net revenue interest in the Development Wells. Chesapeake s actual net revenue interest in any particular Development Well may differ from this average.

Chesapeake will retain 10% of the proceeds from the sale of oil, natural gas and natural gas liquids attributable to its net revenue interest in the Producing Wells, and 50% of the proceeds from the sale of future production attributable to its net revenue interest in the Development Wells. Chesapeake initially will own 50% of the trust units (without giving effect to the exercise of the underwriters over-allotment option). By virtue of Chesapeake s retained interest in the Producing Wells and the Development Wells, as well as its ownership of 50% of the trust units, it would have an effective average net revenue interest of 29.8% in the Producing Wells and 38.4% in the Development Wells, compared with an effective average net revenue interest for the holders of trust units other than Chesapeake of 24.4% in the Producing Wells and 12.8% in the Development Wells.

The trust will not be responsible for any costs related to the drilling of the Development Wells or any other operating and capital costs. The trust s cash receipts in respect of the trust properties will be determined after deducting post-production expenses and any applicable taxes associated with the PDP Royalty Interest and the Development Royalty Interest. These post-production expenses 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. However, the trust will not be responsible for costs of marketing services provided by Chesapeake. Cash distributions to unitholders will be increased or decreased by the effect of the trust s hedging arrangements related to oil and natural gas production and reduced by trust administrative expenses.

The trust will be a party to hedging arrangements with unaffiliated counterparties covering a portion of production through March 31, 2016. 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. The trust will hedge approximately % of the expected production and % of the expected revenues (based on NYMEX strip oil and natural gas prices as of June 20, 2011) upon which the target distributions from April 1, 2011 through March 31, 2016 are based. Following this offering, except in limited circumstances involving the restructuring of an existing hedge, the trust will have no ability to terminate its hedging arrangements or enter into additional hedges of its own. No production after March 31, 2016 will be hedged. Substantially all of the trust s assets will be pledged to the hedge counterparties to provide credit support for the hedge transactions. 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, approximately 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 Chesapeake. The remaining 50% of each of the PDP Royalty Interest and the Development Royalty Interest will be sold by the trust, and the net proceeds of the sale, as well as any remaining trust cash reserves, will be distributed to the unitholders pro rata. Chesapeake will have a right of first refusal to purchase these royalty interests retained by the trust at the Termination Date.

Chesapeake currently operates 95% of the Producing Wells and expects to operate approximately 93% of the Development Wells until the completion of its drilling obligation. Chesapeake will market or cause to be marketed oil, natural gas and natural gas liquids produced from the Underlying Properties. The conveyance instruments obligate Chesapeake to conduct operations and market production in good faith and in accordance with the Reasonably Prudent Operator Standard described below under The Development Wells.

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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. Chesapeake 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. Please see Description of the Trust Units Voting Rights of Trust Unitholders.

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 Development Wells

Pursuant to a development agreement with the trust, Chesapeake intends to drill, or cause to be drilled, 122 Development Wells on PUD drilling locations in the AMI by March 31, 2015 and is obligated to complete such drilling by March 31, 2016. Chesapeake will be credited for drilling one full Development Well if the perforated length of the well is equal to or greater than 3,500 feet and Chesapeake s net revenue interest in the well is equal to 51.2%. For wells with a perforated length that is less than 3,500 feet, and for wells in which Chesapeake has a net revenue interest greater than or less than 51.2%, Chesapeake will receive proportionate credit. As a result, Chesapeake may be required to drill more or less than 122 wells in order to fulfill its drilling obligation. See The Trust Development Agreement and Drilling Support Lien. As of the date of this prospectus, there were five wells within the AMI awaiting completion by Chesapeake. Assuming the successful drilling, completion and equipping of these wells, such wells will count toward the satisfaction of Chesapeake s drilling obligation.

Until Chesapeake has satisfied its drilling obligation, it will not be permitted to drill or complete any well on lease acreage included within the AMI for its own account. For the life of the trust, Chesapeake will not be permitted to drill or complete any well that will have a perforated segment within 600 feet of any perforated interval of any Development Well or Producing Well.

In drilling the Development Wells, Chesapeake is required to act diligently and as a reasonably prudent oil and gas operator would act under the same or similar circumstances as if it were acting with respect to its own properties, disregarding the existence of the royalty interests as burdens affecting such properties. We refer to this standard as the Reasonably Prudent Operator Standard. Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the Development Wells will be generally consistent with those used for the Producing Wells and other Colony Granite Wash producing wells outside of the AMI. The proved undeveloped reserves reflected in the reserve reports assume that Chesapeake will drill and complete the 122 Development Wells with the same completion technique as the 60 Producing Wells. Chesapeake Exploration, L.L.C. (Chesapeake Exploration), an indirect wholly owned subsidiary of Chesapeake that holds the interests in the AMI, will grant to the trust a lien on its interest in the AMI (except the Producing Wells and any other wells that 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 $277.2 million. As Chesapeake fulfills its drilling obligation over time, the total dollar amount that may be recovered will be proportionately reduced and completed Development Wells will be released from the lien. After Chesapeake 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 trust s royalty interests.

As of the date of this prospectus, Chesapeake s drilling activity with respect to the Development Wells is consistent with the drilling schedule contemplated by the development agreement. The drilling schedule provides that approximately 30 wells are expected to be drilled each year until the drilling obligation is fulfilled.

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Underlying Properties

The Underlying Properties are located in the Colony Granite Wash play in Washita County in western Oklahoma. The Colony Granite Wash is a subset of the greater Granite Wash plays of the Anadarko Basin. The Colony Granite Wash is situated at the eastern end of a series of Des Moines-age granite wash fields that extend along the southern flank of the Anadarko basin, approximately 60 miles into the Texas Panhandle. These granite wash fields were generally deposited as deep-water turbidites that result in relatively low risk, laterally extensive and hydrocarbon liquids-rich reservoirs. The productive members of the Colony Granite Wash are encountered between approximately 11,500 and 13,000 feet and lie stratigraphically between the top of the Des Moines formation (or top of Colony Granite Wash A) and the top of the Prue formation (or base of Colony Granite Wash C). The individual productive members within the Colony Granite Wash may reach 200 feet or more in gross interval thickness and the targeted porosity zones within these individual members are generally 20 to 75 feet thick.

Chesapeake began drilling horizontal wells in the Colony Granite Wash in 2007. Chesapeake is the largest leaseholder in the Colony Granite Wash, with approximately 61,100 net acres (of which 28,700 net acres will be subject to the trust s royalty interests), the most active driller in the play, based on rig count, and the largest producer in the play. Since 2007, there have been 164 Des Moines horizontal wells drilled in the Colony Granite Wash. Of those 164 wells, Chesapeake has drilled 122 wells and participated in another 37 wells. As of March 31, 2011, there were 12 rigs drilling horizontal wells in the formation, with nine of those rigs drilling for Chesapeake. While horizontal wells are more expensive than vertical wells, a horizontal well increases the production of hydrocarbons and adds significant recoverable reserves per well. In addition, an operator can achieve better returns on drilling investments with horizontal drilling because the production from one horizontal well is equal to the production from several vertical wells. While Chesapeake is the most active company in this play, other operators in the Colony Granite Wash include publicly-listed companies such as Penn Virginia Corporation, Apache Corporation, QEP Resources, Inc., SM Energy Company and Marathon Oil Corporation, and privately- held companies such as Samson Oil & Gas Limited, Chaparral Energy, Inc. and Ward Petroleum Corporation.

Target Distributions and Subordination and Incentive Thresholds

Chesapeake has established quarterly target levels of cash distributions to unitholders for the life of the trust as set forth in Annex B to this prospectus. 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 such production, when Chesapeake receives payment for such production, payments under the hedge arrangements, the trust s administrative expenses and other factors. As shown in Annex B, while target distributions initially increase as Chesapeake 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 reports included as Annex A to this prospectus 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 June 20, 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 2022 and the price of natural gas would reach the $7.00 per mmbtu cap in 2023. The target distributions also give effect to estimated post-production expenses and projected trust administrative expenses.

In order to provide support for cash distributions on the common units, Chesapeake has agreed to subordinate 12,687,500 of the trust units it will retain following this offering, which will constitute 25% of the outstanding trust units. The subordinated units will be entitled to receive pro rata distributions from the trust each

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quarter if and to the extent there is sufficient cash to pay 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 Chesapeake. 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 portion of its trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake 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 Chesapeake, on a pro rata basis.

By way of example, if the target distribution per unit for a particular quarterly period is $0.80, then the subordination threshold would be $0.64 and the incentive threshold would be $0.96 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 $0.64, 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 $0.96, then Chesapeake would receive 50% of the amount by which the cash available for distribution on all the trust units exceeds $0.96, with all trust unitholders (including Chesapeake 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 Chesapeake 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 Chesapeake 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. Chesapeake currently intends to complete its drilling obligation on or before March 31, 2015 and accordingly, Chesapeake expects the subordinated units will convert into common units on or before March 31, 2016. Chesapeake is obligated to complete its drilling obligation by March 31, 2016, 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.

Chesapeake s management has prepared the prospective financial information set forth below to present the target cash 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. Chesapeake 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 production or financial information.

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The prospective financial information included in this prospectus has been prepared by, and is the responsibility of, Chesapeake s management. PricewaterhouseCoopers LLP, the trust s and Chesapeake s independent registered public accountant, has neither examined, compiled nor performed any procedures with respect to the accompanying prospective financial information and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The reports of PricewaterhouseCoopers LLP included or incorporated by reference in this prospectus relate to the Statement of Assets and Trust Corpus of the trust, the historical Statements of Revenues and Direct Operating Expenses of the Underlying Properties and the historical financial statements of Chesapeake. The reports do not extend to the prospective financial information and should not be read to do so.

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The following table sets forth the target distributions and subordination and incentive thresholds for each calendar quarter through the first quarter of 2017 (the last quarter for which subordinated units would be outstanding if Chesapeake were to complete its drilling obligation on March 31, 2016). 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 (April 1, 2011 through August 31, 2011). Thereafter, quarterly distributions will generally include royalties attributable to 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. 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 (per unit)	Incentive Threshold(1)
2011:			
Second and Third Quarters(2)	$ 0.85	$ 1.06	$ 1.27
Fourth Quarter	0.52	0.65	0.78
2012:			
First Quarter	0.57	0.72	0.86
Second Quarter	0.58	0.72	0.87
Third Quarter	0.65	0.81	0.97
Fourth Quarter	0.74	0.93	1.12
2013:			
First Quarter	0.71	0.89	1.07
Second Quarter	0.64	0.80	0.96
Third Quarter	0.67	0.84	1.01
Fourth Quarter	0.71	0.88	1.06
2014:			
First Quarter	0.73	0.91	1.10
Second Quarter	0.71	0.88	1.06
Third Quarter	0.72	0.90	1.08
Fourth Quarter	0.70	0.88	1.05
2015:			
First Quarter	0.70	0.87	1.05
Second Quarter	0.68	0.85	1.01
Third Quarter	0.58	0.73	0.88
Fourth Quarter	0.53	0.66	0.79
2016			
First Quarter	0.48	0.60	0.72
Second Quarter	0.45	0.56	0.68
Third Quarter	0.42	0.53	0.63
Fourth Quarter	0.40	0.50	0.60
2017			
First Quarter	0.38	0.48	0.57

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(1) The subordination and incentive thresholds terminate after the fourth full calendar quarter following Chesapeake 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 the establishment of $1.0 million of reserves for administrative expenses withheld by the trustee.

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 Chesapeake based on assumptions of production volumes, pricing and other factors. The production forecasts used to calculate target distributions are based on estimates by Ryder Scott contained in the reserve reports. Payments to unitholders will be made approximately 60 days following the end of each calendar quarter. Please read Target Distributions and Subordination and Incentive Thresholds Significant Assumptions Used to Calculate the Target Distributions.

Period	Five Months Ending September 30, 2011(1)	Three Months Ending December 31, 2011(1)	March 31, 2012(1)	June 30, 2012(1)
	(In thousands, except volumetric and per unit data)			
Estimated production from trust properties				
Oil sales volumes (mbbls)	245	154	168	168
Natural gas liquids sales volumes (mbbls)	438	273	284	289
Natural gas sales volumes (mmcf)	4,222	2,634	2,754	2,782
Total sales volumes (mboe)	1,386	866	911	921
% PDP sales volumes	92%	70%	59%	53%
% PUD sales volumes	8%	30%	41%	47%
% Oil volumes	18%	18%	19%	18%
% Natural gas liquids volumes	31%	31%	31%	31%
% Natural gas volumes	51%	51%	50%	51%
Commodity price and derivative contract positions				
NYMEX futures price(2)				
Oil ($/bbl)	$ 100.12	$ 94.47	$ 95.51	$ 96.44
Natural gas ($/mmbtu)	$ 4.32	$ 4.46	$ 4.81	$ 4.70
Assumed realized weighted unhedged price(3)				
Oil ($/bbl)	$ 96.54	$ 90.89	$ 91.93	$ 92.86
Natural gas liquids ($/bbl)	$ 46.76	$ 44.04	$ 44.56	$ 45.01
Natural gas ($/mcf)	$ 2.99	$ 3.11	$ 3.40	$ 3.28
Assumed realized weighted hedged price*(4)				
Oil ($/bbl)*				
Natural gas ($/mcf)*				
Percent of oil volumes hedged*				
Oil hedged price ($/bbl)*				
Percent of natural gas volumes hedged*				
Natural gas hedged price ($/mmbtu)*				
Estimated cash available for distribution				
Oil sales revenues	$ 23,613	$ 13,967	$ 15,418	$ 15,623
Natural gas liquids sales revenues	20,472	12,022	12,657	13,007
Natural gas sales revenues	12,639	8,193	9,366	9,119
Realized gains (losses) from derivative contracts*				
Operating revenues and realized gains (losses) from derivative contracts	56,724	34,182	37,441	37,749
Production taxes	(1,437)	(814)	(863)	(872)
Trust administrative expenses	(1,417)(5)	(250)	(250)	(250)

Total trust expenses	(2,854)	(1,064)	(1,113)	(1,122)
Cash available for distribution	$ 53,870	$ 33,118	$ 36,328	$ 36,627
Trust units outstanding	50,750	50,750	50,750	50,750
Target distribution per trust unit	$ 1.06	$ 0.65	$ 0.72	$ 0.72
Subordination threshold per trust unit	$ 0.85	$ 0.52	$ 0.57	$ 0.58
Incentive threshold per trust unit	$ 1.27	$ 0.78	$ 0.86	$ 0.87

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(1) The five months ending September 30, 2011 include proceeds attributable to five months of production from April 1, 2011 to August 31, 2011. Thereafter, quarterly distributions will generally include royalties attributable to 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.

(2) Average NYMEX settled and futures prices, as reported June 20, 2011. For a description of the effect of lower NYMEX prices on target cash 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 gravity 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) No hedging arrangements will cover natural gas liquids.

(5) Includes the establishment of a cash reserve of $1.0 million for trust administrative expenses.

* Information with respect to assumed realized weighted hedged price for oil ($/bbl) and natural gas ($/mcf), percent of oil volumes hedged, oil hedged price ($/bbl), percent of natural gas volumes hedged and natural gas hedged price ($/mmbtu) will be provided after hedging arrangements are finalized with respect to estimated future production attributable to the royalty interests.

Chesapeake Energy Corporation

Chesapeake is the second-largest producer of natural gas, is among the top 15 producers of oil and natural gas liquids and is the most active driller, based on rig count, of new oil and natural gas wells in the U.S. Chesapeake s operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Haynesville, Bossier, Marcellus and Pearsall natural gas shale plays and in the Granite Wash, Cleveland, Tonkawa, Mississippian, Bone Spring, Avalon, Wolfcamp, Wolfberry, Eagle Ford, Niobrara, Three Forks/Bakken and Utica unconventional liquids plays. It has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. As of March 31, 2011, Chesapeake had total assets of approximately $34.8 billion and total estimated net proved reserves of 15.6 tcfe. Chesapeake has approximately 61,100 net acres leased in the Colony Granite Wash and as of March 31, 2011, Chesapeake was operating nine rigs in the Colony Granite Wash.

Chesapeake s principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118 and its telephone number is (405) 848-8000. Chesapeake s website is *www.chk.com*; however, the information contained on Chesapeake s website is not incorporated by reference into this prospectus.

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

Key Investment Considerations

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

The royalty interests being contributed to the trust are from the highly-productive Colony Granite Wash Play. The existing Producing Wells and the Development Wells to be drilled target the Colony Granite Wash play within the broader Granite Wash formation of the Anadarko Basin. This highly-productive play has been a focus area for recent development, with 164 horizontal wells targeting the Des Moines formation drilled in the Colony Granite Wash since 2007. Of those 164 wells, Chesapeake has drilled

122 wells and participated in another 37 wells. As of March 31, 2011, there were 12 active rigs drilling horizontal wells in the play, with nine of those rigs drilling for Chesapeake.

Liquids-weighted revenue and production profiles provide long-term exposure to oil prices. Over the 20-year producing life of the trust, 73% of net revenues (based on June 20, 2011 strip prices) and 47% of production are projected to be derived from oil and natural gas liquids. As a result, the unhedged portion of liquids revenues during the hedge period and all liquids revenues beyond the hedge period are directly exposed to oil prices, and the amount of trust distributions and consequently trust performance is expected to be highly correlated to fluctuations in the price of oil.

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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 its proportionate share of post-production expenses, any applicable taxes and trust administrative expenses.

Exposure to oil and natural gas price volatility mitigated through March 31, 2016. The trust will be a party to hedging arrangements with unaffiliated counterparties covering a portion of expected production through March 31, 2016. The trust will hedge approximately % of the expected production and approximately % of the expected revenues (based on NYMEX strip oil and natural gas prices as of June 20, 2011) upon which the target distributions from April 1, 2011 through March 31, 2016 are based. These hedging arrangements are expected to reduce the trust s exposure to fluctuations in the prices of oil and natural gas through the first quarter of 2016.

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

- Chesapeake will have a significant economic interest in the Underlying Properties through its 50% retained interest in the Development Wells, 10% retained interest in the Producing Wells and its ownership of approximately 50% of the trust units.

- A portion of the trust units that Chesapeake will own, constituting 25% of the total outstanding trust units, will be subordinated units that will not be entitled to receive distributions unless there is sufficient cash to pay the subordination threshold amount to the common units. In addition, these subordinated units will only convert into common units at the end of the fourth full calendar quarter following Chesapeake 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, Chesapeake 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 25,375,000 total units.

- Chesapeake will not be permitted to drill or complete any wells for its own account within the AMI or sell the Underlying Properties until it has satisfied its drilling obligation.

- If Chesapeake does not fulfill its drilling obligation by March 31, 2016, the trust may foreclose on its lien on the Underlying Properties. See The Trust Development Agreement and Drilling Support Lien.

The Colony Granite Wash represents a core asset for Chesapeake. The approximately 61,100 net acres held by Chesapeake in the Colony Granite Wash represent one of its core assets. Chesapeake has grown its position in the Colony Granite Wash since it began drilling horizontal wells there in 2007 based on its belief that the formation can provide attractive returns on invested capital and its belief that the play will further Chesapeake s goal of increasing the proportion of its liquids production. As of March 31, 2011, Chesapeake had nine rigs drilling horizontal wells in the Colony Granite Wash.

Chesapeake is an experienced operator in the Colony Granite Wash. Since 2007, Chesapeake has drilled, as operator, 122 of the 164 horizontal wells drilled by the industry in the Colony Granite Wash to date, 117 of which are completed and the remaining five of which are awaiting completion and expected to be productive. Of the 122 horizontal wells drilled by Chesapeake in the Colony Granite Wash, 117 are located in Washita County, in which the Underlying Properties are located. Chesapeake expects to operate approximately 93% of the Development Wells until the completion of its drilling obligation, allowing Chesapeake to control the timing and amount of discretionary expenditures for operational and development activities with respect to the majority of the Development Wells.

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The Colony Granite Wash is serviced by well-developed gathering systems and transportation pipelines. Chesapeake s affiliate, Chesapeake Midstream Partners, L.P. (Chesapeake Midstream Partners), provides Chesapeake with gathering, treating and compression services for natural gas produced in the Colony Granite Wash and is expected to continue to provide these services with respect to substantially all of the natural gas and natural gas liquids produced by the Underlying Properties. The natural gas gathering systems are connected to an extensive intrastate natural gas transportation pipeline system owned by Enogex LLC (Enogex), a subsidiary of publicly-held OGE Energy Corp. Chesapeake s wholly owned subsidiary, Chesapeake Midstream Development, L.P. (Chesapeake Midstream Development), gathers oil production from the Colony Granite Wash through its gathering systems and third parties gather other oil by truck. The oil is further transported to Plains All American Pipeline, L.P. (Plains), a publicly-held master limited partnership, through its pipeline and by truck. The well-developed gathering systems in the Colony Granite Wash and Chesapeake s affiliation with the primary service providers allow close coordination regarding the availability of midstream services and reduce the risk that such services would not be available as Development Wells are drilled.

Rigs and services readily available to allow timely drilling and completion of wells. Chesapeake s substantial oilfield service operations, including drilling rigs, pressure pumping equipment, trucking, oilfield tools, location and road construction and roustabout services, support its drilling activities and will allow Chesapeake to manage the development of the trust s leasehold efficiently and strategically. As of March 31, 2011, Chesapeake had nine drilling rigs operating in the Colony Granite Wash and owned or leased a total of 91 drilling rigs, which it uses to drill wells for its own account. Chesapeake estimates that only four to five rigs will be required to complete its drilling obligation within its contractual commitment to the trust. Chesapeake may use a combination of its own rigs and oilfield service businesses and third party rigs and services to drill and complete the Development Wells. Chesapeake s direct access to drilling rigs and related oilfield services should substantially mitigate any potential shortage of drilling and completion equipment and enable Chesapeake to achieve its projected drilling schedule.

Potential for initial depletion to be offset by results of development drilling. Chesapeake intends to drill, or cause to be drilled, all of the Development Wells on PUD drilling locations in the AMI by March 31, 2015 and is obligated to complete such drilling by March 31, 2016. Furthermore, Chesapeake is incentivized to increase production in the near term due to its substantial ownership of trust units, the subordination and incentive distribution provisions of those units and its retained interest in the Underlying Properties. While production from the trust properties will decline over the long term, the anticipated production from the Development Wells is expected to more than offset depletion of the Producing Wells during the drilling period.

Recognized sponsor with a successful track record and active drilling program. Chesapeake maintains the industry s most active drilling program, based on rig count. In 2010, Chesapeake drilled 1,445 gross (938 net) operated wells and participated in another 1,586 gross (211 net) wells operated by other companies. Chesapeake s drilling success rate in 2010 was 98% for both company-operated and non-operated wells. Daily production for 2010 averaged 2.836 bcfe, an increase of 355 mmcfe, or 14%, over the 2.481 bcfe of daily production for 2009, and consisted of 2.534 bcf of natural gas (89% on a natural gas equivalent basis) and 50,397 bbls of oil and natural gas liquids (11% on a natural gas equivalent basis). 2010 was Chesapeake s 21st consecutive year of production growth.

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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 reports. The reserve reports were prepared by Ryder Scott 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 Chesapeake 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 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 prior to the Termination Date as well as the residual 50% interest in the royalty interests that the trust will own on the Termination Date and subsequently sell. A summary of the reserve reports is included as Annex A to this prospectus.

	Proved Reserves[1]				
	Natural Gas (mmcf)	Oil (mbbl)	Natural Gas Liquids (mbbl)	Total (mboe)	PV-10 Value[2] (In thousands)
Underlying Properties:					
Developed	67,948	2,292	6,916	20,533	$ 296,600
Undeveloped	185,762	8,506	19,458	58,924	$ 447,736
Total	253,710	10,798	26,374	79,457	$ 744,336
Royalty Interests:					
PDP Royalty Interests (90%)	54,517	1,935	5,552	16,573	$ 276,534
Development Royalty Interests (50%)	82,888	4,106	8,676	26,597	$ 469,688
Total	137,405	6,041	14,228	43,170	$ 746,222

(1) The proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil, natural gas and natural gas liquids 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 reports, as well as Chesapeake 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 presented in the table below.

	Trailing 12-month average (SEC) pricing			Weighted average wellhead prices		
	Natural gas (per mcf)	Oil (per bbl)	Natural gas liquids (per bbl)	Natural gas (per mcf)	Oil (per bbl)	Natural gas liquids (per bbl)
March 31, 2011	$ 4.10	$ 83.34	$ 83.34	$ 2.78	$ 79.80	$ 37.98

(2) 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% (as required by the SEC), 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 the same. 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 the same. 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 our 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. PV-10 for the royalty interests has been calculated without deduction for production and development costs, as the trust will not bear those costs.

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Underlying Production Attributable to Target Distributions. The following production bar graph summarizes estimated production underlying trust revenues used to determine Target Distributions.

(1) Due to the April 1, 2011 effective date of the trust and the timing of payments received by the trust for production in determining the Target Distributions, the 2011 production forecast includes production from April 1, 2011 through November 30, 2011.

(2) Due to the March 31, 2031 termination date of the trust and the timing of payments received by the trust for production in determining Target Distributions, the 2031 production forecast includes production from December 1, 2030 to March 31, 2031.

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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 20.

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 cash available for distributions to unitholders.

Prices of oil, natural gas and natural gas liquids fluctuate due to a number of factors that are beyond the control of the trust and Chesapeake, and lower prices could reduce proceeds to the trust, Chesapeake s economic incentive to drill 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.

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

Chesapeake may not serve as the operator of as many of the Developmental Wells as it expects and Chesapeake will rely upon unaffiliated third parties, who may be less qualified, to drill Development Wells where Chesapeake is not the operator.

The oil, natural gas and natural gas liquids reserves estimated to be attributable to the Underlying Properties 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 hedging arrangements for the trust will cover only a portion of the production attributable to the trust, such arrangements will limit the trust s ability to benefit from commodity price increases for hedged volumes, and such arrangements will be secured by substantially all of the trust s assets and may require the trust to make cash payments in excess of its receipts. Following this offering, except in limited circumstances involving the restructuring of an existing hedge, the trust will have no ability to terminate its hedging arrangements or enter into additional hedges on its own.

Conflicts of interest could arise between Chesapeake and the trust.

Potential legislative and regulatory actions could increase Chesapeake s costs, reduce its revenue and cash flow from the sale of oil, natural gas and natural gas liquids, reduce its liquidity or otherwise alter the way it conducts business.

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 or the trust were subjected to state or local entity level tax, 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 trust s tax positions, 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.

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Structure of the Trust

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

* Chesapeake is expected to have an effective average net revenue interest of 29.8% in the Producing Wells and 38.4% in the Development Wells. Public unitholders (that is, holders of trust units other than Chesapeake) are expected to have an effective average net revenue interest of 24.4% in the Producing Wells and 12.8% in the Development Wells.

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The Offering

Common units offered to public	25,375,000 common units (29,181,250 common units, if the underwriters exercise their over-allotment option in full)
Trust units owned by Chesapeake after the offering	12,687,500 common units and 12,687,500 subordinated units (8,881,250 common units and 12,687,500 subordinated units, if the underwriters exercise their over-allotment option in full)
Total units outstanding after the offering	38,062,500 common units and 12,687,500 subordinated units
Over-allotment option	3,806,250 common units will be issued and retained by the trust at the initial closing, to be used to satisfy (if necessary) the 30-day 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 subsidiaries of Chesapeake 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 one or more subsidiaries of Chesapeake as partial consideration for the conveyance of the Perpetual Royalties, promptly following the 30th day after the initial closing. See The Trust Formation Transactions.
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 and an initial public offering price of $ per common unit, the estimated net proceeds of this offering will be approximately $ million, after deducting underwriting discounts and commissions and estimated offering expenses. The trust will deliver the net proceeds to a wholly owned subsidiary of Chesapeake, as consideration for the conveyance of the Term Royalties. See The Trust Formation Transactions.
	Chesapeake intends to use the offering proceeds, including proceeds from any exercise of the underwriters over-allotment option, to repay borrowings under its credit facility. Chesapeake may re-borrow amounts under its credit facility from time to time and does so for general corporate purposes, including capital expenditures for land, drilling and other costs. See Use of Proceeds. Affiliates of certain of the underwriters are lenders under Chesapeake s credit facility and, in that respect, will receive a portion of the proceeds from this offering through the repayment of borrowings outstanding under the facility. See Underwriting.
Proposed NYSE symbol	CHKR
Trustee	The Bank of New York Mellon Trust Company, N.A.

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Quarterly cash distributions	Quarterly cash distributions during the term of the trust will be made by the trustee approximately 60 days following the end of each calendar quarter to unitholders of record approximately 45 days following the end of each calendar quarter. 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. Thereafter, quarterly distributions will generally include royalties attributable to 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.
	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 such production, when Chesapeake receives payment for such production, payments under the hedge arrangements, the trust s administrative expenses 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 a majority of the common units (excluding common units owned by Chesapeake and its affiliates) and 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. Chesapeake and its affiliates will not be entitled to vote on the removal of the trustee or appointment of a successor trustee. However, if at any time Chesapeake and its affiliates own less than 10% of the outstanding trust units, matters voted on by trust unitholders will be subject to approval by a majority of the trust units, including units owned by Chesapeake, voting in person or by proxy at a meeting of such holders at which a quorum is present.
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 Chesapeake. 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

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	reserves, will be distributed to the unitholders pro rata. Chesapeake 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 cash 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 interest 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	The trust 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 % 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 $ per unit.
	Please read U.S. Federal Income Tax Considerations for more information.

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RISK FACTORS

Before making an investment decision, you should carefully consider the risks described below and the risks described in Chesapeake s Annual Report on Form 10-K for the year ended December 31, 2010, which is incorporated herein by reference. 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, and 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 cash available for distribution to unitholders.

The drilling and completion of the Development Wells are subject to numerous risks beyond Chesapeake s and the trust s control, including risks that could delay or change 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. Chesapeake 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 could cause Chesapeake to re-direct its drilling capital to other plays and delay the drilling of the Development Wells beyond what was assumed in establishing target levels of cash distributions to unitholders. 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 or irregularities in formations;
- 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;

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;

lack of sufficient water or water disposal facilities in connection with hydraulic fracturing;

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;

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- adverse weather conditions, such as extreme cold, fires caused by extreme heat or lack of rain and severe storms or tornadoes;
- reductions in oil, natural gas and natural gas liquids prices or, for hedged production, increases in pricing differentials; and
- title problems affecting the Underlying Properties.

If 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.

Prices of oil, natural gas and natural gas liquids fluctuate due to a number of factors that are beyond the control of the trust and Chesapeake, and lower prices could reduce proceeds to the trust, Chesapeake s economic incentive to drill 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 Chesapeake. These factors include, among others:

- regional, domestic and foreign supply, and perceptions of supply, of oil, natural gas and natural gas liquids;
- the price and level of foreign imports of oil, natural gas and natural gas liquids, including political instability or armed conflict in producing regions;
- 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, 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;
- natural disasters;

- the nature and extent of domestic and foreign governmental regulations and taxation;
- energy conservation and environmental measures;
- the price and availability of alternative fuels and energy sources;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others; and
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls.

For oil, from 2007 through 2010, the highest monthly NYMEX settled price was $134.62 per bbl and the lowest was $33.87 per bbl. For natural gas, from 2007 through 2010, the highest monthly NYMEX settled price was $13.11 per mmbtu and the lowest was $2.84 per mmbtu. In addition, the market price of oil, natural gas and natural gas liquids is generally higher in the winter months than during other months of the year due to increased demand for oil, natural gas and natural gas liquids for heating purposes during the winter season.

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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, Chesapeake 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 Underlying Properties could determine during periods of low oil, natural gas and natural gas liquids 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, Chesapeake 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 Chesapeake 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. There can be no assurance that the trust s hedging program will mitigate these risks. 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, such arrangements will limit the trust s ability to benefit from commodity price increases for hedged volumes, and such arrangements will be secured by substantially all of the trust s assets and may require the trust to make cash payments in excess of its receipts.

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. The future production estimates are based on estimates of reserve quantities for the Underlying Properties. 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 expenses incurred and results of actual development could materially decrease reserve estimates.

Reserve estimates for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in estimates of proved reserves, future production rates and the timing of development expenditures. Most of the Producing Wells have been operational for a relatively short period of time and estimated total reserves vary substantially from well to well and are not directly correlated to perforated lateral length or completion technique. There can be no assurance that the data used in preparing these estimates can accurately predict future production. The lack of operational history for horizontal wells in the Colony Granite Wash may also contribute to the inaccuracy of estimates of proved reserves. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates, would have a material adverse effect on the financial condition, results of operations and cash flows of the trust and would reduce cash distributions to trust unitholders.

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As with all horizontal drilling programs, there is a risk that some or all of a horizontal well could miss the target reservoir. As a result, the trust may not receive the benefit, or any revenue from, some or all of the proved undeveloped reserves reflected in the reserve reports, notwithstanding the fact that Chesapeake has satisfied its drilling obligation. See Summary The Development Wells.

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, have been established by Chesapeake, and Chesapeake has not received an opinion or report on such calculations from any independent accountants, financial advisers or engineers. Such estimates 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 assume 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 June 20, 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 (which cap would be reached in 2022) and $7.00 per mmbtu of natural gas (which cap would be reached in 2023); however, actual sales prices may not increase at this rate or at all and may instead decline. Additionally, these estimates assume that the Development Wells will be drilled on Chesapeake s current anticipated schedule and the related Underlying Properties will achieve production volumes set forth in the reserve reports; 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 cash 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 Chesapeake does not ensure that you will in fact receive any specified return on your investment in the trust.

Although Chesapeake 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 Chesapeake s completion of its drilling obligation. Depending on the prices at which Chesapeake is able to sell volumes attributable to the trust, the common units may receive a distribution that is below the subordination threshold.

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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 Chesapeake s historical financial statements for periods prior to the trust s formation or initial public offering. The historical financial information for the Underlying Properties included in this prospectus does not give effect to the terms and conditions of the royalty interests and, as a result, does not reflect what the trust s distributable income will be in the future.

In preparing the pro forma statements of distributable income included in this prospectus, Chesapeake has made adjustments to the historical pro forma financial information for the Underlying Properties based upon currently available information and upon assumptions that Chesapeake 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.

Chesapeake may not serve as the operator of as many of the Developmental Wells as it expects and Chesapeake will rely upon unaffiliated third parties, who may be less qualified, to drill Development Wells where Chesapeake is not the operator.

Pursuant to the development agreement between Chesapeake and the trust, Chesapeake is obligated to drill, or cause to be drilled, 122 Development Wells in the AMI. Although Chesapeake expects to operate approximately 93% of the Development Wells until the completion of its drilling obligation, another working interest owner or a contract operator could serve as the operator for certain Development Wells. Chesapeake will rely upon these third-party operators to drill the Development Wells where it is not the operator. The ability of third-party operators to help Chesapeake meet the drilling obligation 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 an operator to adequately perform operations could reduce production from the Underlying Properties and the cash available for distribution to trust unitholders. Chesapeake 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.

Because Chesapeake does not have a majority working interest in the non-operated properties comprising the Underlying Properties, Chesapeake may not be able to remove the operator in the event of poor or untimely performance. If the Development Wells take longer to be drilled 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.

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For those Development Wells where Chesapeake is the operator, Chesapeake may rely on third party servicers to conduct the drilling operations.

Although Chesapeake owns substantial oilfield service assets, where Chesapeake is the operator of a Development Well, it may rely on third-party service providers to perform the necessary drilling operations. The ability of third-party service providers to perform such drilling operations will depend on those service providers 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 service provider to adequately perform operations could delay drilling or completion or reduce production from the Underlying Properties and the cash available for distribution to trust unitholders. 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.

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 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 Chesapeake 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 Colony Granite Wash in Washita County in western Oklahoma. 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 markets or the area of the Underlying Properties, including, for example, transportation or treatment capacity constraints, curtailment of production or treatment plant 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 the availability of gathering, transportation and processing facilities. Even where such facilities are available, services from such facilities are 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 or physical damage to the

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gathering system or transportation system. The curtailments may vary from a few days to several months. In many cases, Chesapeake or a third-party operator is provided limited notice, if any, as to when production will be curtailed and the duration of such curtailments. If Chesapeake or a third-party operator 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. Moreover, Chesapeake currently ships all of its natural gas production from the Underlying Properties to market through one pipeline provider and sells all of its oil production from the Underlying Properties to one purchaser. Although Chesapeake 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 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, Chesapeake may not be able to sell the 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. Any delay in the procurement of additional transportation capacity would delay the receipt of any proceeds that may be associated with production from the Development Wells.

The trust units may lose value and cash available for distribution may be reduced 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. Chesapeake does not obtain title insurance covering oil, natural gas and mineral leaseholds. Additionally, undeveloped leasehold acreage has greater risk of title defects than developed acreage.

Prior to the drilling of a Development Well, Chesapeake intends to obtain a drilling title opinion to identify defects in title to the leasehold. Frequently, as a result of such examinations, certain curative work may be required to correct identified title defects, and such curative work entails time and expense. Chesapeake s inability or failure to cure title defects could render some locations undrillable or cause Chesapeake 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 may be reduced.

The trust is passive in nature and will have no stockholder voting rights in Chesapeake, managerial, contractual or other ability to influence Chesapeake, 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 Chesapeake securities and will have no managerial, contractual or other ability to influence Chesapeake s activities or operations of the Underlying Properties. In addition, some of the Development Wells will be operated by third parties unrelated to Chesapeake. Such third-party operators may not have the operational expertise of Chesapeake within the AMI. Oil and gas 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.

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The oil, natural gas and natural gas liquids reserves estimated to be attributable to the Underlying Properties 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 Chesapeake s commitment to drill the Development Wells, Chesapeake has no contractual obligation to the trust to make capital expenditures on the Underlying Properties in the future. Furthermore, for properties on which Chesapeake is not designated as the operator, Chesapeake has no control over the timing or amount of those capital expenditures. Chesapeake also has the right not to participate in the capital expenditures on properties for which it is not the operator, in which case Chesapeake and the trust will not receive the production resulting from such capital expenditures. If Chesapeake 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 Chesapeake or estimated in the reserve reports.

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 agreements 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 Chesapeake 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 Chesapeake s oil, natural gas and natural gas liquids production in Oklahoma 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, post-production expenses and severance taxes. These factors can cause differentials to be volatile from period to period. Chesapeake 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. For 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.

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

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 expenses incurred by Chesapeake to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and natural gas liquids (excluding costs of marketing services provided by Chesapeake);

- the trust s share of applicable taxes on the oil, natural gas and natural gas liquids; and

- trust administrative expenses, including fees paid to the trustee and the Delaware trustee, the annual administrative services fee payable to Chesapeake, 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.

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, Chesapeake 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 exceeds 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 expenses and applicable taxes for the producing lives of the Producing Wells and Development Wells, see The Underlying Properties. Historical post-production expenses and taxes, however, may not be indicative of future post-production expenses and taxes.

The hedging arrangements for the trust will cover only a portion of the production attributable to the trust, such arrangements will limit the trust s ability to benefit from commodity price increases for hedged volumes, and such arrangements will be secured by substantially all of the trust s assets and may require the trust to make cash payments in excess of its receipts.

The trust will be a party to oil and natural gas hedging arrangements with unaffiliated counterparties. The trust will hedge approximately % of the expected production and % of the expected revenues (based on NYMEX strip oil and natural gas prices as of June 20, 2011) upon which the target distributions from April 1, 2011 through March 31, 2016 are based. Expressed in terms of oil and natural gas production, approximately % of the estimated oil production from April 1, 2011 through March 31, 2016, and approximately % of the estimated natural gas production from April 1, 2011 through March 31, 2016, will be hedged. The remaining estimated production of oil and natural gas during that time, all production of natural gas liquids during that time, and all production after such time will not be 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 or terminate existing hedges on its own. With respect to unhedged volumes and periods, the trust will not be protected against the price risks inherent in holding interests in oil and natural gas, commodities that are 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 and natural gas prices above the hedge price on the portion of the production attributable to the trust s royalty interests that is hedged.

Chesapeake will act as hedge manager to the trust pursuant to the administrative services agreement. In fulfilling its role as hedge manager, Chesapeake will not act as a fiduciary for the trust, will have no affirmative

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duty to modify any of the trust s hedges, and will have no liability to the trust in connection with Chesapeake s failure to modify, or any affirmative modification of, any of the trust s hedges. Moreover, Chesapeake will be indemnified by the trust for any actions it takes in this regard.

The trust s receipt of any payments due to it based on the trust s hedging arrangements depends upon the financial position of the trust s unaffiliated hedge counterparties. If any of the counterparties to the oil and natural gas hedging arrangements were to 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.

If actual production, over which the trust has no control, is below the amounts forecast in the reserve reports and oil, natural gas 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 entered into between the trust and unaffiliated counterparties provide the trust with the right to receive from the hedge counterparties 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 its hedge counterparties 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 hedging arrangements. 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. If these payments become too large, the trust s liquidity and cash available for distribution may be adversely affected.

The trust s obligations to the counterparties under its hedging arrangements 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 hedging arrangements 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. If the trust were to default on its hedging arrangements, the counterparties could foreclose on substantially all of the trust s assets.

Please see The Trust Hedging Arrangements for more details on the prices and production volumes associated with the trust s hedging arrangements.

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

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 is less than $1.0 million in each of any four consecutive quarters. 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, after the payment of trust liabilities, will be distributed to the trust unitholders pro rata and unitholders will not be entitled to receive any proceeds from the sale of production from the Underlying Properties following such date. If none of these events occur, the trust will dissolve on the Termination Date.

In connection with the dissolution of the trust on the Termination Date, the Term Royalties will automatically revert to Chesapeake, while the Perpetual Royalties will be sold and the proceeds will be distributed to the unitholders (including Chesapeake to the extent of any trust units it owns) at the date the trust dissolves or soon thereafter. The price received by the trust from any purchaser of the Perpetual Royalties will

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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 the Perpetual Royalties.

Chesapeake will have a right of first refusal to purchase the Perpetual Royalties upon the dissolution of the trust, 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 Chesapeake and wants to sell all or part of the Perpetual Royalties to such third party, the trustee will be required to give notice to Chesapeake 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 Chesapeake 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 Chesapeake, the trust or the underwriters will obtain any independent appraisal or other opinion of the value of the royalty interests other than the reserve reports prepared by Ryder Scott.

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 Chesapeake, 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 Chesapeake s liability to the trust is limited.

The trust agreement permits the trustee and the trust to sue Chesapeake 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 trust or the trustee to compel the trust or the trustee to take specified actions. The trust agreement expressly limits a trust unitholder s ability to directly sue Chesapeake or any other party other than the trustee. As a result, trust unitholders will not be able to sue Chesapeake 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, Chesapeake 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 in accordance with the Reasonably Prudent Operator Standard 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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Chesapeake 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, Chesapeake will hold an aggregate of 12,687,500 common units (assuming no exercise by the underwriters of the over-allotment option) and 12,687,500 subordinated units. All of the subordinated units will automatically convert into common units at the end of the subordination period. Chesapeake 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 and Raymond James & Associates, Inc. See Underwriting. After such period, Chesapeake 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 Chesapeake, which, if exercised, would facilitate sales of common units by Chesapeake to the public. See Trust Units Eligible for Future Sale Registration Rights Agreement.

Conflicts of interest could arise between Chesapeake and the trust.

Chesapeake could have interests that conflict with the interests of the trust and the trust unitholders. For example:

Notwithstanding its drilling obligation to the trust, Chesapeake 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, Chesapeake may abandon a well that is no longer producing in paying quantities even though such well is still generating revenue for the trust unitholders. Subsequent to fulfilling its drilling obligation, Chesapeake 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.

Chesapeake 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 Chesapeake s experience in the Colony Granite Wash or its creditworthiness.

Chesapeake may, without the consent of the trust unitholders, require the trust to release 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 only in connection with the sale by Chesapeake of the Underlying Properties and are conditioned upon the trust receiving an amount equal to the fair value to the trust of such royalty interests. See The Underlying Properties Sale and Abandonment of the Underlying Properties.

Chesapeake Midstream Partners provides Chesapeake with gathering, treatment and compression services with respect to natural gas and Chesapeake Midstream Development provides Chesapeake with gathering services with respect to oil in the Colony Granite Wash. These Chesapeake affiliates are expected to provide these services with respect to substantially all of the Underlying Properties. The amounts charged by Chesapeake Midstream Partners and Chesapeake Midstream Development are post-production expenses that are deducted from trust revenues before making distributions to trust unitholders. Provisions in the conveyance agreements require that charges under contracts with Chesapeake Midstream Partners, Chesapeake Midstream Development or other affiliates of Chesapeake, for such post-production expenses, not materially exceed charges prevailing in the area for similar services.

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

In addition, Chesapeake 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,

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Chesapeake will lend 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 Chesapeake and an unaffiliated third party. If Chesapeake 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.

Chesapeake 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 Chesapeake.

You will not be entitled to vote on any sale of the Underlying Properties and the trust will not receive any proceeds from any such sale. The purchaser would be responsible for all of Chesapeake s obligations relating to the royalty interests on the portion of the Underlying Properties sold, and Chesapeake would have no continuing obligation to the trust for those properties. Additionally, Chesapeake may enter into farmout or joint venture arrangements with respect to the wells burdened by the trust s royalty interests. 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 Chesapeake.

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

Pursuant to the terms of the development agreement, Chesapeake will be obligated to drill, or cause to be drilled, the Development Wells at its own expense. Chesapeake expects to operate approximately 93% of such wells until the completion of its drilling obligation. Chesapeake also currently operates 95% of the Producing Wells. The conveyances provide that Chesapeake will be obligated to market, or cause to be marketed, the oil, natural gas and natural gas liquids production related to the Underlying Properties. Due to the trust s reliance on Chesapeake to fulfill these obligations, the value of the trust s royalty interests and its ultimate cash available for distribution will be highly dependent on Chesapeake s performance.

Chesapeake 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 Chesapeake s control. See Chesapeake Energy Corporation and Where You Can Find More Information for additional information relating to Chesapeake.

If Chesapeake were to default on its obligation to drill the Development Wells, the trust would be able to foreclose on the Drilling Support Lien to the extent of Chesapeake s remaining interests in the undeveloped portions of the AMI. The maximum amount the trust can recover in such a foreclosure action is approximately $277.2 million, which amount will be reduced proportionately as each Development Well is drilled and will not be adjusted for inflation over time. There can be no assurance that the value of Chesapeake s interests in the undeveloped portions of 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 and may result in the loss of acreage due to leasehold expirations. Any amounts actually recovered in a foreclosure action would be applied to completion of Chesapeake 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

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within a reasonable period of time. As long as the trust s royalty interests are pledged as collateral to the trust s hedge counterparties, arranging for a replacement driller or operator may be more difficult or impossible. In such an event, the production from the trust s properties would decline and such decline may trigger a foreclosure on the trust s assets by the hedging counterparties. The possibility of this foreclosure could deter the trust from exercising its right to foreclose on the drilling lien.

The proceeds of the royalty interests may be commingled, for a period of time, with proceeds of Chesapeake s retained interest in the Underlying Properties, and Chesapeake will not be required to maintain a segregated account for proceeds payable to the trust. In the event of a collection proceeding, 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 Chesapeake s retained interest, be able to assert claims to the proceeds that should be delivered to the trust. In addition, during any bankruptcy of Chesapeake, it is possible that payments of the royalties may be delayed or deferred. During the pendency of any Chesapeake bankruptcy proceedings, the trust s ability to foreclose on the Drilling Support Lien, and the ability to collect cash payments being held in Chesapeake s accounts that are attributable to production from the trust properties, and even its ability to demand any of these remedies, may be stayed or prohibited by the bankruptcy proceeding. 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 Chesapeake was able to achieve.

Oil and gas drilling and producing operations can be hazardous and may expose Chesapeake to liabilities, including environmental liabilities.

Oil and gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of natural gas, oil, brine or well fluids and other environmental hazards and risks. Chesapeake s drilling operations involve risks from high pressures and from mechanical difficulties such as stuck pipes, collapsed casings and separated cables. Some of these risks or hazards could materially and adversely affect Chesapeake s revenues and expenses by reducing or shutting in production from wells or otherwise negatively impacting the projected economic performance of its prospects. A temporary or permanent halt of the production and sale of oil, natural gas and natural gas liquids at any of the Underlying Properties could also reduce trust distributions by reducing the amount of proceeds available for distribution.

Additionally, if any of these risks occurs, Chesapeake could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- clean-up responsibilities;

- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

There is also inherent risk of incurring significant environmental costs and liabilities in oil and gas operations due to the generation, handling and disposal of materials, including wastes and petroleum hydrocarbons. Chesapeake may incur joint and several, strict liability under applicable U.S. federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from its leased or owned properties, some of which have been used for natural gas and oil exploration and production activities for a number of years, often by third parties not under its control. For

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non-operated properties, Chesapeake is dependent on the operator for operational and regulatory compliance. See The Underlying Properties Regulation for a discussion of environmental regulation applicable to Chesapeake.

If Chesapeake experiences any of the problems described above, its ability to conduct operations and perform its obligations to the trust could be adversely affected. While Chesapeake intends to obtain and maintain insurance coverage it deems appropriate with respect to the Underlying Properties, Chesapeake s operations may result in liabilities exceeding such insurance coverage or liabilities not covered by insurance. If a well is damaged, Chesapeake would have no obligation to drill a replacement well or make the trust whole for the loss. The trust will have no insurance or indemnification to protect against losses or delays in receiving proceeds from such events.

Potential legislative and regulatory actions could increase Chesapeake s costs, reduce its revenue and cash flow from the sale of oil, natural gas and natural gas liquids, reduce its liquidity or otherwise alter the way it conducts business.

The activities of exploration and production companies operating in the United States are subject to extensive regulation at the federal, state and local levels. Changes to existing laws and regulations or new laws and regulations such as those described below could, if adopted, have an adverse effect on Chesapeake s business and could reduce cash received by or available for distribution from the trust.

Federal Taxation of Producers of Natural Gas and Oil

Federal budget proposals would potentially increase and accelerate the payment of federal income taxes of producers of natural gas and oil. Proposals that would significantly affect Chesapeake would repeal the expensing of intangible drilling costs, the percentage depletion allowance and lengthen the amortization period of geological and geophysical expenses. These changes, if enacted, will make it more costly for Chesapeake to explore for and develop its natural gas and oil resources.

OTC Derivatives Regulation

In July 2010, the U.S. Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which contains measures aimed at increasing the transparency and stability of the over-the-counter (OTC) derivative markets and preventing excessive speculation. The trust will engage in hedging activities to manage the risk of low commodity prices and to predict with greater certainty the cash flow from its hedged production. The Dodd-Frank Act and the rules and regulations promulgated thereunder could reduce trading positions in the energy futures markets. Such changes could materially reduce hedging opportunities for the trust and negatively affect its revenues and cash flow during periods of low commodity prices.

Hydraulic Fracturing

Hydraulic fracturing, the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into the formation, is used in completing greater than 90% of all natural gas and oil wells drilled today in the United States. While hydraulic fracturing is typically regulated by state oil and gas commissions, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the Safe Drinking Water Act s Underground Injection Control Program and has begun the process of drafting guidance documents for permitting authorities and the industry on the process for obtaining a permit for hydraulic fracturing involving diesel fuel. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012. 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

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chemicals used in the fracturing process. Chesapeake cannot predict whether additional hydraulic fracturing federal, state or local laws or regulations will be enacted and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed through the adoption of new laws and regulations, Chesapeake s operations with respect to the Underlying Properties could be subject to delays, increased operating and compliance costs and process prohibitions. Restrictions on hydraulic fracturing could also reduce the amount of oil, natural gas and natural gas liquids that Chesapeake is ultimately able to produce in commercial quantities from the Underlying Properties.

Climate Change

Various state governments and regional organizations comprising state governments are considering enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as Chesapeake s equipment and operations. At the federal level, the EPA has already made findings and issued regulations that require Chesapeake to establish and report an inventory of greenhouse gas emissions and that could lead to the imposition of restrictions on greenhouse gas emissions from stationary sources used in oil and gas operations. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require Chesapeake to incur additional operating costs and could adversely affect demand for oil, natural gas and natural gas liquids. The potential increase in operating costs could include new or increased costs to obtain permits, operate and maintain equipment and facilities, install new emission controls on equipment and facilities, acquire allowances to authorize greenhouse gas emissions, pay taxes related to our greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for oil, natural gas and natural gas liquids.

For more information on environmental and regulatory risks, please read The Underlying Properties Regulation.

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 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 or the trust were subjected to state or local entity level tax, 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 such treatment is applicable to it, 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.

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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%, and would likely be required to pay state income tax on its taxable income at the corporate tax rate in Oklahoma. 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 taxation as a corporation or otherwise subjects it to entity-level taxation for U.S. federal, state or local income tax purposes, the subordination threshold amounts and the target distribution amounts may be adjusted to reflect the impact of that law on the trust.

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. It has been assumed that the effective rate of production tax on the oil, natural gas and natural gas liquids attributable to the trust will be approximately 1.0% for the first four years of production for each well, and approximately 7.0% thereafter. 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. Any such legislation would likely also affect the trust tax treatment for state tax purposes.

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.

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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.

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 these 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.

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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 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 technical termination of the trust 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

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

You may be subject to state and local taxes and return filing requirements in jurisdictions where you do not live as a result of investing in trust units.

In addition to federal income taxes, trust unitholders will likely be subject to other taxes, including Oklahoma state income taxes, even if they do not live in Oklahoma. You will likely be required to file Oklahoma state income tax returns and pay Oklahoma state income tax. Further, you may be subject to penalties for failure to comply with those requirements. It is each trust unitholder s responsibility to file all U.S. federal, state, local and non-U.S. tax returns.

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 interests such as the Perpetual Royalties, 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 Chesapeake 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 Chesapeake 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 Chesapeake 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, 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 Chesapeake 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 Chesapeake s Annual Report on Form 10-K for the year ended December 31, 2010, and other disclosures about Chesapeake, the trust and the Underlying Properties 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 and an initial public offering price of $ per common unit, the estimated net proceeds of this offering will be approximately $ million, after deducting underwriting discounts and commissions and estimated offering expenses. The trust will deliver all of the net proceeds to a wholly owned subsidiary of Chesapeake, as consideration for the conveyance of the Term Royalties.

At the initial closing, 3,806,250 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 Chesapeake s wholly owned subsidiary 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 Chesapeake s wholly owned subsidiary as partial consideration for the conveyance of the Perpetual Royalties promptly following the 30th day after the initial closing.

Chesapeake intends to use the net proceeds received from this offering to repay borrowings under its credit facility. Chesapeake may re-borrow amounts under its credit facility from time to time and does so for general corporate purposes, including capital expenditures for land, drilling and other costs. Affiliates of certain of the underwriters are lenders under Chesapeake s credit facility and, in that respect, will receive a portion of the proceeds from this offering through the repayment of borrowings outstanding under the facility. See Underwriting. As of June 30, 2011, the outstanding balance on Chesapeake s credit facility, which matures on December 2, 2015, was approximately $1.7 billion, and the weighted average interest rate of the credit facility was 1.95%. Borrowings under the credit facility in the past year were incurred by Chesapeake for general corporate purposes, including capital expenditures for land, drilling and other costs.

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CHESAPEAKE ENERGY CORPORATION

Chesapeake is the second-largest producer of natural gas, is among the top 15 producers of oil and natural gas liquids and is the most active driller, based on rig count, of new oil and natural gas wells in the U.S. Chesapeake s operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Haynesville, Bossier, Marcellus and Pearsall natural gas shale plays and in the Granite Wash, Cleveland, Tonkawa, Mississippian, Bone Spring, Avalon, Wolfcamp, Wolfberry, Eagle Ford, Niobrara, Three Forks/Bakken and Utica unconventional liquids plays. It has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. As of March 31, 2011, Chesapeake had total assets of approximately $34.8 billion and total estimated net proved reserves of 15.6 tcfe. Chesapeake has approximately 61,100 net acres leased in the Colony Granite Wash and as of March 31, 2011, Chesapeake was operating nine rigs in the Colony Granite Wash.

Chesapeake s principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118 and its telephone number is (405) 848-8000. Chesapeake s website is *www.chk.com*; however, the information contained on Chesapeake s website is not incorporated by reference into this prospectus.

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

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THE TRUST

The trust is a statutory trust created under the Delaware Statutory Trust Act in June 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 Chesapeake will operate most of the Underlying Properties, Chesapeake 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, 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 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 for paying other expenses incurred as a result of being a publicly traded entity, including costs associated with annual and quarterly reports to unitholders, and this offering. Trust administrative expenses are anticipated to aggregate approximately $1,000,000 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 $175,000 for the trustee, which may be adjusted beginning on January 1, 2015 as provided in the trust agreement, an annual administrative fee of $2,000 for the Delaware trustee and an annual fee of $200,000 payable to Chesapeake pursuant to the terms of the administrative services agreement. The trustee will also receive a one-time acceptance fee of $10,000. These costs will be deducted from revenues by the trust before distributions are made to trust unitholders. The trustee intends to withhold $1.0 million from the first distribution to establish a cash reserve available for trust administrative expenses.

Formation Transactions

At or prior to the closing of the offering, Chesapeake will cause to be conveyed to the trust a 90% royalty interest in the Producing Wells and a 50% royalty interest in the Development Wells. The conveyance will be effective as of April 1, 2011.

The 90% royalty interest in the Producing Wells will consist of a term royalty interest entitling the trust to receive 45% of the proceeds from the sale of oil, natural gas and natural gas liquids production attributable to Chesapeake s net revenue interest in the Producing Wells (after deducting post-production expenses 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 45% of the proceeds from the sale of oil, natural gas and natural gas liquids production attributable to Chesapeake s net revenue interest in the Producing Wells (after deducting post-production expenses and any applicable taxes) (the Perpetual PDP Royalty).

The 50% royalty interest in the Development Wells will consist of a term royalty interest entitling the trust to receive 25% of the proceeds from the sale of the production of oil, natural gas and natural gas liquids attributable to Chesapeake s net revenue interest in the Development Wells (after deducting post-production expenses 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 25% of the proceeds from the sale of oil, natural gas and natural gas liquids production attributable to Chesapeake s net revenue interest in the Development Wells (after deducting post-production expenses 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 Chesapeake Exploration to the trust. The Term Royalties will be conveyed from Chesapeake Exploration to another wholly owned subsidiary of Chesapeake in exchange for a demand note in a principal amount expected to be substantially the same as the amount of the net proceeds of the offering (assuming no exercise of the underwriters overallotment option), and then assigned from that subsidiary to the trust. In exchange for the Term Royalties and the Perpetual Royalties, the trust will issue to Chesapeake Exploration 12,687,500 common units and 12,687,500 subordinated units, and will deliver all of the net proceeds of this offering (assuming no exercise of the underwriters overallotment option) to the other Chesapeake subsidiary, which will use such proceeds to repay the demand note to Chesapeake Exploration. See Use of Proceeds.

The trust will issue and retain 3,806,250 common units 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 Chesapeake s wholly owned subsidiary as partial consideration for the conveyance of the Perpetual Royalties. If the underwriters do not exercise the over-allotment option, the retained units will be delivered to Chesapeake s wholly owned subsidiary, as partial consideration for the conveyance of the Perpetual Royalties, promptly following the 30th day after the initial closing.

The trust will sell the 25,375,000 common units offered hereby to the public, representing a 50% interest in the trust.

Chesapeake and the trust will enter into several agreements in connection with the conveyance of the royalty interests, including: (a) a development agreement, which sets forth Chesapeake s drilling obligation to the trust with respect to the Development Wells, (b) an administrative services agreement, which sets forth Chesapeake s obligation to provide administrative services to the trust, (c) the Drilling Support Lien and (d) a registration rights agreement, which is described under Trust Units Eligible For Future Sale Registration Rights Agreement. These first three agreements are described in more detail below.

Termination Date; Liquidation

Unless the occurrence of certain events causes the trust to dissolve at an earlier date, 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 Chesapeake, while the Perpetual Royalties will be sold and the proceeds will be distributed to the unitholders pro rata 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. Chesapeake will have a right of first refusal to purchase the Perpetual Royalties retained by the trust at the Termination Date. 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 Chesapeake, Chesapeake Exploration and Chesapeake Operating, Inc., a wholly owned subsidiary of Chesapeake, that will obligate Chesapeake to drill, or cause to be drilled, all of the Development Wells. Chesapeake intends to drill, or cause to be drilled, the Development Wells in the Colony Granite Wash on PUD drilling locations in the AMI by March 31, 2015 and is obligated to complete such drilling by March 31, 2016.

Chesapeake Exploration will grant to the trust the Drilling Support Lien, covering Chesapeake Exploration s interest in the AMI (except the Producing Wells and any other wells that 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 amount obtained by the trust pursuant to the Drilling Support Lien may not exceed $277.2 million. As Chesapeake 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, a Development Well is calculated based on the perforated length of the well (measured from the first perforation along the measured depth to the last perforation along the measured depth) and Chesapeake s net revenue interest in such well. Chesapeake will be credited for drilling one full Development Well if the perforated length of the well is equal to or greater than 3,500 feet and Chesapeake s net revenue interest in the well is equal to 51.2%.

For wells with a perforated length that is less than 3,500 feet, Chesapeake will receive partial credit equal to the fraction calculated by dividing the well s perforated length by 3,500 feet. Chesapeake will not receive any extra credit for wells with perforated lengths in excess of 3,500 feet.

For wells in which Chesapeake has a net revenue interest greater than or less than 51.2%, Chesapeake will receive credit for such well in the proportion that its net revenue interest in the well bears to 51.2%.

Accordingly, for example, if Chesapeake drilled one well in which it has a 80% net revenue interest, and such well were completed with a perforated length of 3,500 feet, such well would count for purposes of the development agreement as 1.56 Development Wells (i.e., 3,500/3,500 X 80%/51.2%). If, on the other hand, Chesapeake drilled one well in which it has a 50% net revenue interest, and such well were completed with a perforated length of 3,000 feet, such well would count for purposes of the development agreement as only 0.84 Development Wells (i.e., 3,000/3,500 X 50%/51.2%).

Given that Chesapeake s actual net revenue interest in each Development Well may be greater than or less than 51.2% and the perforated length of each well drilled may be greater or less than 3,500 feet, Chesapeake may be required to drill more or less than 122 wells in order to fulfill its drilling obligation.

In drilling the Development Wells, Chesapeake is required to adhere to the Reasonably Prudent Operator Standard. Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the Development Wells will be generally consistent with those used for the Producing Wells and other Colony Granite Wash producing wells outside of the AMI.

Following the drilling of each Development Well, Chesapeake is obligated to attempt to complete each such well that reasonably appears to Chesapeake, acting in accordance with the Reasonably Prudent Operator Standard, to be capable of producing in quantities sufficient to pay completion, equipping and operating costs. Following successful completion of such wells, Chesapeake is obligated to equip such wells for production and connect such wells to a gathering line, pipeline or other storage or marketing facility and commence production.

Chesapeake may, and anticipates that it will, rely on third-party operators to fulfill a portion of its drilling, completion and equipping obligation. The trust will not bear any of the costs of drilling, completing and equipping the Development Wells that Chesapeake drills or causes to be drilled.

The PUD reserves reflected in the reserve reports assume that Chesapeake will drill and complete the 122 Development Wells with the same completion technique as the 60 Producing Wells. These 60 Producing Wells produce from perforated interval lengths contributing to production ranging from less than 2,300 feet to more than 4,600 feet. The average perforated interval length contributing to production of the 60 Producing Wells is approximately 4,100 feet, which is longer than the 3,500 foot perforated interval length upon which the definition of one full Development Well is based.

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Because (a) the average perforated interval length of the wells assumed for purposes of calculating the PUD reserves is longer than the minimum perforated interval length required for Chesapeake to receive credit for one full Development Well and (b) there is no guarantee that wells drilled with shorter perforated interval lengths will achieve the same reserve recoveries as wells drilled with longer perforated interval lengths, you may not receive the benefit of the total amount of PUD reserves reflected in the reserve reports, notwithstanding that Chesapeake has satisfied its drilling obligation. In addition to its obligation to adhere to the Reasonably Prudent Operator Standard, Chesapeake s significant retained economic interest in the trust wells through its working interest, trust unit ownership and its opportunity to earn incentive distributions provide it with substantial incentives to pursue well completions with perforated interval lengths greater than 3,500 feet to the extent necessary to optimize reserve recoveries for the benefit of the trust.

Chesapeake will covenant and agree not to drill or complete, and will not permit any other person within its control to drill or complete, any well in the AMI other than a Development Well until such time as Chesapeake has met its commitment to drill the Development Wells. Once Chesapeake has completed its drilling obligation, the trustee will be required to release the Drilling Support Lien in full. Chesapeake will further agree not to drill or complete, and will not permit any other person within its control to drill or complete, any well that will have a perforated segment that will be within 600 feet of any perforated interval of a Development Well or Producing Well.

Hedging Arrangements

The trust will be a party to hedging arrangements with unaffiliated counterparties covering a portion of production through March 31, 2016. 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.

If one or more counterparties to the trust s hedging arrangements were to default on its 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, natural gas and natural gas liquids prices. Chesapeake will have authority, in its role as hedge manager to the trust, to terminate, restructure or otherwise modify a portion of the trust s hedging arrangements to the extent that Chesapeake 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 at the end of the first quarter of 2016, no production will be hedged. For more information on Chesapeake s role as hedge manager for the trust, please see Administrative Services Agreement.

The trust s obligations to the counterparties under its hedging arrangements 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 hedging arrangements 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 trust agreement, the trustee may create a cash reserve to pay for future liabilities of the trust.

Under the hedging arrangements, the trust will hedge approximately % of the expected production and % of the expected revenues (based on NYMEX strip oil and natural gas prices as of June 20, 2011) upon which the target distributions from April 1, 2011 through March 31, 2016 are based. Expressed in terms of oil and natural gas production, approximately % of the estimated oil production from April 1, 2011 through March 31, 2016, and approximately % of the estimated natural gas production from April 1, 2011 through March 31, 2016, will be hedged. The remaining estimated production of oil and natural gas during that time, all production of natural gas liquids during that time and all production after such time will not be hedged.

The following tables illustrate the type of contract, notional amount and weighted average fixed price for the hedging arrangements into which the trust will enter.

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	Volume (mbbl)	Weighted Average Price (per bbl)
Oil:		
Swaps:		
Q2 2011		
Q3 2011		
Q4 2011		
Q1 2012		
Q2 2012		
Q3 2012		
Q4 2012		
Q1 2013		
Q2 2013		
Q3 2013		
Q4 2013		
Q1 2014		
Q2 2014		
Q3 2014		
Q4 2014		
Q1 2015		
Q2 2015		
Q3 2015		
Q4 2015		
Q1 2016		
Total Oil		

	Volume (bbtu)	Weighted Average Price (per mmbtu)
Natural Gas:		
Swaps:		
Q2 2011		
Q3 2011		
Q4 2011		
Q1 2012		
Q2 2012		
Q3 2012		
Q4 2012		
Q1 2013		
Q2 2013		
Q3 2013		
Q4 2013		
Q1 2014		
Q2 2014		
Q3 2014		
Q4 2014		
Q1 2015		
Q2 2015		
Q3 2015		
Q4 2015		
Q1 2016		
Total Natural Gas		

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Administrative Services Agreement

In connection with the closing of this offering, the trust will enter into an administrative services agreement with Chesapeake pursuant to which Chesapeake 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 Chesapeake as the trust s hedge manager, pursuant to which Chesapeake will have authority, on behalf of the trust, to administer the trust s hedging arrangements. As hedge manager, Chesapeake will also have authority, in its discretion, to terminate, restructure or otherwise modify any or all of such hedging arrangements to the extent that Chesapeake 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. Chesapeake will be required to use commercially reasonable efforts to effect such modifications to the hedging arrangements 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, Chesapeake 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 Chesapeake s failure to modify, or any affirmative modification of, any of the trust s hedges. Moreover, Chesapeake will be indemnified by the trust for any actions it takes in this regard.

In return for the services provided by Chesapeake to the trust under the administrative services agreement, the trust will pay Chesapeake, on a quarterly basis, a total annual fee of $200,000. Chesapeake 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 Chesapeake, the date that either Chesapeake or the trustee may designate by delivering 90-days prior written notice, provided that Chesapeake s drilling obligation has been completed and the transferee of such Underlying Properties assumes responsibility to perform the services in place of Chesapeake, or (d) a date mutually agreed by Chesapeake and the trustee.

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TARGET DISTRIBUTIONS AND SUBORDINATION AND INCENTIVE THRESHOLDS

Chesapeake 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 90% of the proceeds (exclusive of any production or development costs but after deducting post-production expenses and any applicable taxes) from the sale of oil, natural gas and natural gas liquids production attributable to Chesapeake s net revenue interest in the Producing Wells. The Development Royalty Interest will entitle the trust to receive 50% of the proceeds (exclusive of any production or development costs but after deducting post-production expenses and any applicable taxes) from the sale of future production of oil, natural gas and natural gas liquids attributable to Chesapeake s net revenue interest in the Development Wells.

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;