CHESAPEAKE ENERGY CORP
Form S-1/A
October 18, 2011
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As filed with the Securities and Exchange Commission on October 18, 2011

Registration No. 333-175395

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Amendment No. 3 **to** **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**	**Amendment No. 3** **to** **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**

(512) 236-6599	**(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** **Hillary H. Holmes** **Baker Botts L.L.P.** **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	¨

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 October 18, 2011

22,875,000 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 option to purchase additional units), 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 $19.00 and $21.00 per common unit. The common units have been 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 liquids and natural gas 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 69 horizontal producing wells and (b) 50% of the proceeds attributable to Chesapeake s net revenue interest in the sale of production from 118 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 liquids and natural gas 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 liquids hedges to which the trust will be a party. For information on target distributions and related matters pertinent to trust unitholders, including Chesapeake s right to receive incentive distributions and ownership of subordinated units, please see Target Distributions and Subordination and Incentive Thresholds beginning on page 50.*

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

These risks include the following:

- *Drilling for and producing oil, natural gas liquids and natural gas involves many risks that could delay the anticipated drilling schedule for the development wells and adversely affect future production, which could decrease cash distributions to unitholders.*
- *Price fluctuations for oil, natural gas liquids and natural gas could reduce proceeds to the trust and decrease cash distributions to unitholders.*

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

Estimates of target distributions to unitholders are based on assumptions that are inherently subjective and are subject to significant risks and uncertainties that could cause actual distributions to differ materially from estimates.

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

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

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

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

PRICE $ A COMMON UNIT

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

(1) *Excludes an aggregate 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 an option to purchase up to an additional 3,431,250 common units.

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*

Deutsche Bank Securities *Goldman, Sachs & Co.* *Wells Fargo Securities*

, 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 beginning on page 121. Ryder Scott Company, L.P., referred to in this prospectus as Ryder Scott, an independent engineering firm, provided the estimates of proved oil, natural gas liquids and natural gas reserves as of June 30, 2011 included in this prospectus. These estimates are contained in summaries prepared by Ryder Scott of its reserve reports for (a) the properties held by Chesapeake from which the royalty interests will be conveyed to the trust 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 $20.00 per common unit (the midpoint of the price range set forth on the cover page of this prospectus) and no exercise of the underwriters option to purchase additional common units.

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 69 existing horizontal wells in the Colony Granite Wash play located in Washita County in western Oklahoma (the Producing Wells), and (b) royalty interests in 118 horizontal development wells (calculated as described under The Development Wells beginning on page 3) to be drilled exclusively in the Colony Granite Wash (the Development Wells) on properties within an Area of Mutual Interest (as such area may be extended as described below, the 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, currently consisting of approximately 45,400 gross acres (28,700 net acres) held by Chesapeake. 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 June 30, 2015 and is obligated to complete such drilling by June 30, 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 July 1, 2011. As of July 1, 2011, 64 of the Producing Wells were producing from the Colony Granite Wash and the remaining five Producing Wells had been drilled and were awaiting completion. As of October 1, 2011, all of the Producing Wells were completed and producing. 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 liquids and natural gas 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 liquids and natural gas production attributable to Chesapeake s net revenue interest in the Development Wells.

As of June 30, 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 44.3 mmboe (47.0% oil and natural gas liquids by volume). This amount includes 18.6 mmboe attributable to the PDP Royalty Interest and 25.7 mmboe attributable to the Development Royalty Interest.

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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 52.8% net revenue interest in the Producing Wells. Therefore, the trust will have an average 47.5% net revenue interest in the Producing Wells. Chesapeake on average owns a 52.0% 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 26.0% net revenue interest in the Development Wells. Chesapeake s actual net revenue interest in any particular Producing Well or Development Well may differ from these averages.

Chesapeake will retain 10% of the proceeds from the sale of oil, natural gas liquids and natural gas 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 option to purchase additional common units). 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 29.0% in the Producing Wells and 39.0% in the Development Wells, compared with an effective average net revenue interest for the holders of trust units other than Chesapeake of 23.8% in the Producing Wells and 13.0% 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 liquids and natural gas 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 liquids production and reduced by trust expenses.

The trust will be a party to hedging arrangements covering a portion of its oil and natural gas liquids production through September 30, 2015. 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 50% of the expected oil and natural gas liquids production and 37% of the trust s expected revenues (based on NYMEX strip oil prices as of October 14, 2011) upon which the target distributions from October 1, 2011 through September 30, 2015 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. Except in connection with the restructuring of an existing hedge, no production after September 30, 2015 will be hedged. The trust s royalty interests in the Underlying Properties will be pledged to the hedge counterparties to provide credit support for the hedge transactions, and the hedging counterparties may foreclose on such lien if, among other things, the trust or Chesapeake is in material default of the drilling, payment or reporting obligations under the hedging arrangements, subject to applicable cure and notice periods. Please see The Trust Hedging Arrangements beginning on page 47 and Target Distributions and Subordination and Incentive Thresholds beginning on page 50.

The trust will make quarterly cash distributions of substantially all of its cash receipts, after deducting the trust s expenses, approximately 60 days following the completion of each quarter through (and including) the quarter ending June 30, 2031. The first distribution, which will cover the third quarter of 2011 (consisting of proceeds attributable to two months of production), is expected to be made on or about December 1, 2011 to record unitholders on or about November 21, 2011. The Bank of New York Mellon Trust Company, N.A., as trustee, intends to withhold $1.0 million from the first distribution to establish an initial cash reserve available for trust expenses.

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The PDP Royalty Interest and the Development Royalty Interest will each consist of two separate royalty interests conveyed by Chesapeake to the trust: (a) a term royalty interest for a period of 20 years commencing on July 1, 2011 and ending on June 30, 2031 (such date is referred to as the Termination Date and such interests are referred to as the Term Royalties) and (b) a perpetual royalty interest that does not terminate (together, the Perpetual Royalties). The trust will dissolve and begin to liquidate on the Termination Date and will soon thereafter wind up its affairs and terminate. At the Termination Date, the Term Royalties will revert automatically to Chesapeake. Following the Termination Date, the Perpetual Royalties 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 the Perpetual Royalties from the trust following the Termination Date.

Chesapeake currently operates 94% 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, the oil, natural gas liquids and natural gas 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 under The Development Wells below.

Prior to fulfilling its drilling obligation to the trust, Chesapeake may cause the trust to exchange leased acreage in the AMI for other leased acreage in the sections adjacent to the AMI (such adjacent sections are referred to as the Development Area). If additional acreage in the Development Area becomes subject to the royalty interests, then the AMI will automatically expand to include such acreage. In addition, if Chesapeake acquires any additional leases or interests in the AMI, Chesapeake may make such additional leases or interests subject to the royalty interests of the trust with respect to any Development Wells subsequently drilled on such acreage. However, the aggregate acreage attributable to the exchanged leases or additional leases or acreage may not exceed five percent of the acreage initially subject to the royalty interests and the reserve profile of the newly burdened acreage must be consistent with the reserve profile of the acreage released by the trust. See Description of the Royalty Interests Additional Features of the Royalty Interests Exchange and Addition of Acreage on page 81.

Following the satisfaction of its drilling obligation to the trust, Chesapeake may, without the consent or approval of the trust unitholders, sell all or any part of its retained interest in the Underlying Properties. In any such sale by Chesapeake, the Underlying Properties must be sold subject to and burdened by the trust s royalty interests, except that Chesapeake may require the trust to release the trust s royalty interests on such Underlying Properties with an aggregate value of up to $5.0 million during any 12-month period. In such event, the trust must receive an amount equal to the fair value to the trust of any royalty interests it sells. See Description of the Royalty Interests Additional Features of the Royalty Interests Sale and Release of Underlying Properties on page 81.

The business and affairs of the trust will be managed by the 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 beginning on page 90.

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, 118 Development Wells in the AMI by June 30, 2015 and is obligated to complete such drilling by June 30, 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 52.0%. 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 52.0%, Chesapeake will receive proportionate credit. As a result, Chesapeake may be required to

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drill more or less than 118 wells in order to fulfill its drilling obligation. See The Trust Development Agreement and Drilling Support Lien beginning on page 45. Since July 1, 2011, Chesapeake has drilled and completed six Development Wells and has drilled two additional wells in the AMI that are awaiting completion as of the date of this prospectus. Assuming the successful completion of these two 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 118 Development Wells with the same completion technique as the 69 Producing Wells.

Chesapeake 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 initially may not exceed $262.7 million. As Chesapeake fulfills its drilling obligation over time, Development Wells that are completed or that are perforated for completion and then plugged and abandoned will be released from the Drilling Support Lien and the total dollar amount that may be recovered by the trust for Chesapeake s failure to fulfill its drilling obligation will be proportionately reduced.

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.

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 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. The Colony Granite Wash is primarily a natural gas and natural gas condensate reservoir based on reserve volumes. However, oil and natural gas liquids production generates more revenue than natural gas production in the Colony Granite Wash due to prices that have historically been, and currently are, significantly higher for oil and natural gas liquids than for natural gas. Development costs for horizontal wells drilled and completed in the AMI average

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approximately $8.31 per boe, which is comparable to the development costs in other large-scale resource developments in the Mid-Continent in which Chesapeake operates.

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 172 Des Moines horizontal wells drilled in the Colony Granite Wash. Of those 172 wells, Chesapeake has drilled 132 wells and participated in another 35 wells. As of June 30, 2011, there were 15 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 liquids and natural gas 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 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 liquids and natural gas 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 July through October 2011, monthly NYMEX forward pricing as of October 14, 2011 for the remainder of the period ending June 30, 2014 and assumed price increases after June 30, 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 2026 and the price of natural gas would reach the $7.00 per mmbtu cap in 2028. The target distributions also give effect to estimated post-production expenses, projected trust administrative expenses and actual production for July and August of 2011.

In order to provide support for cash distributions on the common units, Chesapeake has agreed to subordinate 11,437,500 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 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

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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 beginning on page 50.

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 June 30, 2015 and accordingly, Chesapeake expects the subordinated units will convert into common units on or before June 30, 2016. Chesapeake is obligated to complete its drilling obligation by June 30, 2016, in which event the subordinated units would convert into common units on or before June 30, 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 beginning on page 50. The accompanying prospective financial information was not prepared with a view toward complying with the regulations of the U.S. Securities and Exchange Commission (the SEC) or the guidelines established by the American Institute of Certified Public Accountants with respect to preparation and presentation of prospective financial information. More specifically, such information omits items that are not relevant to the trust. 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.

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 second quarter of 2017 (the last quarter for which subordinated units would be outstanding if Chesapeake does not complete its drilling obligation on or before June 30, 2016). The effective date of the conveyance of the royalty interests is July 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 third quarter of 2011, is expected to be made on or about December 1, 2011 to record unitholders on or about November 21, 2011. Due to the timing of the payment of production proceeds to the trust, the trust expects that the first distribution will include royalties attributable to sales of oil, natural gas liquids and natural gas for two months (July and August 2011). Thereafter, quarterly distributions will generally include royalties attributable to sales of oil, natural gas liquids and natural gas for three months, including the first two months of the quarter just ended and the last month of the quarter prior to that one. The trustee intends to withhold $1.0 million from the first distribution to establish an initial cash reserve available for trust expenses.

Period	Subordination Threshold(1)	Target Distribution (per unit)	Incentive Threshold(1)
2011:			
Third Quarter(2)	$ 0.37	$ 0.46	$ 0.55
Fourth Quarter	0.56	0.70	0.85
2012:			
First Quarter	0.59	0.74	0.89
Second Quarter	0.61	0.76	0.91
Third Quarter	0.63	0.79	0.95
Fourth Quarter	0.68	0.85	1.02
2013:			
First Quarter	0.70	0.87	1.05
Second Quarter	0.70	0.87	1.05
Third Quarter	0.72	0.90	1.08
Fourth Quarter	0.70	0.88	1.05
2014:			
First Quarter	0.70	0.88	1.06
Second Quarter	0.69	0.86	1.04
Third Quarter	0.70	0.87	1.05
Fourth Quarter	0.67	0.84	1.00
2015:			
First Quarter	0.67	0.84	1.00
Second Quarter	0.69	0.86	1.03
Third Quarter	0.65	0.81	0.97
Fourth Quarter	0.56	0.70	0.84
2016			
First Quarter	0.51	0.64	0.77
Second Quarter	0.47	0.59	0.71
Third Quarter	0.44	0.55	0.66
Fourth Quarter	0.42	0.52	0.62
2017			
First Quarter	0.39	0.49	0.59
Second Quarter	0.38	0.47	0.56

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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 two months of actual production from July 1, 2011 to August 31, 2011, and gives effect to the establishment of $1.0 million of reserves for 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 beginning on page 50.

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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 beginning on page 56.

Period	Three Months Ending September 30, 2011[1]	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)	103	178	181	181
Natural gas liquids sales volumes (mbbls)	179	299	302	304
Natural gas sales volumes (mmcf)	1,720	2,876	2,909	2,923
Total sales volumes (mboe)	569	956	967	972
% PDP sales volumes	100%	84%	69%	61%
% PUD sales volumes		16%	31%	39%
% Oil volumes	18%	19%	19%	19%
% Natural gas liquids volumes	32%	31%	31%	31%
% Natural gas volumes	50%	50%	50%	50%
Commodity price and derivative contract positions				
NYMEX futures price[2]				
Oil ($/bbl)	$ 95.93	$ 86.03	$ 87.10	$ 87.35
Natural gas liquids ($/bbl)	$ 47.15	$ 42.31	$ 42.85	$ 42.97
Natural gas ($/mmbtu)	$ 4.36	$ 3.78	$ 4.06	$ 4.07
Assumed realized weighted unhedged price[3]				
Oil ($/bbl)	$ 92.35	$ 82.45	$ 83.52	$ 83.77
Natural gas liquids ($/bbl)	$ 44.76	$ 40.01	$ 40.46	$ 40.45
Natural gas ($/mcf)	$ 3.12	$ 2.48	$ 2.81	$ 2.98
Assumed realized weighted hedged price[4]				
Oil ($/bbl)	$ 92.35	$ 81.56	$ 82.34	$ 82.83
Natural gas liquids ($/bbl)	$ 44.76	$ 39.57	$ 39.88	$ 39.99
Percent of oil volumes hedged		33.1%	49.9%	50.0%
Oil hedged price ($/bbl)		$ 84.18	$ 84.74	$ 85.48
Percent of natural gas liquids volumes hedged		33.6%	50.0%	50.0%
Natural gas liquids hedged price ($/bbl)		$ 41.41	$ 41.68	$ 42.05
Estimated cash available for distribution				
Oil sales revenues	$ 9,554	$ 14,648	$ 15,083	$ 15,175
Natural gas liquids sales revenues	8,030	11,953	12,220	12,278
Natural gas sales revenues	5,358	7,120	8,172	8,707
Realized gains (losses) from derivative contracts		(289)	(389)	(309)
Operating revenues and realized gains (losses) from derivative contracts	22,942	33,432	35,085	35,851
Production taxes	(726)	(935)	(938)	(930)

Trust administrative expenses(5)	(1,327)	(250)	(250)	(250)
Total trust expenses	(2,053)	(1,185)	(1,188)	(1,180)
Cash available for distribution	$ 20,890	$ 32,247	$ 33,896	$ 34,670
Trust units outstanding	45,750	45,750	45,750	45,750
Target distribution per trust unit	$ 0.46	$ 0.70	$ 0.74	$ 0.76
Subordination threshold per trust unit	$ 0.37	$ 0.56	$ 0.59	$ 0.61
Incentive threshold per trust unit	$ 0.55	$ 0.85	$ 0.89	$ 0.91

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(1) The three months ending September 30, 2011 include proceeds attributable to two months of production from July 1, 2011 to August 31, 2011. Thereafter, quarterly distributions will generally include royalties attributable to sales of oil, natural gas liquids and natural gas for three months, including the first two months of the quarter just ended as well as the last month of the quarter prior to that one.

(2) Average NYMEX settled and futures prices, as reported October 14, 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 Liquids and Natural Gas Prices and Volumes beginning on page 61.

(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 beginning on page 56.

(4) No hedging arrangements will cover natural gas.

(5) Includes the establishment of an initial cash reserve of $1.0 million for trust expenses in period ending September 30, 2011.

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, Frontier, Codell, Bakken/Three Forks and Utica unconventional liquids plays. It has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. As of June 30, 2011, Chesapeake had total assets of approximately $36.7 billion and total estimated net proved reserves of 16.5 tcfe. Chesapeake has approximately 61,100 net acres leased in the Colony Granite Wash and as of June 30, 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, which is the largest non-shale resource play in the Mid-Continent. This highly-productive play has been a focus area for recent development, with 172 horizontal wells targeting the Des Moines formation drilled in the Colony Granite Wash since 2007. Of those 172 wells, Chesapeake has drilled 132 wells and participated in another 35 wells. As of June 30, 2011, there were 15 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, 72% of net revenues (based on October 14, 2011 strip prices) and 48% of production are projected to be derived from oil and natural gas liquids. Although natural gas liquids typically sell for less than oil on a volume equivalency basis, natural gas liquids prices have historically been highly correlated with oil prices. As a result, the unhedged portion of liquids revenues

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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.

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 and complete the Development Wells. The trust will bear its proportionate share of post-production expenses, any applicable taxes and trust expenses.

Exposure to oil and natural gas liquids price volatility mitigated through September 30, 2015. The trust will be a party to hedging arrangements covering a portion of the trust s expected oil and natural gas liquids production through September 30, 2015. The trust will hedge approximately 50% of the expected oil and natural gas liquids production and approximately 37% of the trust s expected revenues (based on NYMEX strip oil prices as of October 14, 2011) upon which the target distributions from October 1, 2011 through September 30, 2015 are based. These hedging arrangements are expected to reduce the trust s exposure to fluctuations in the prices of oil through the third quarter of 2015.

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 initially 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 22,875,000 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 June 30, 2016, the trust may foreclose on the Drilling Support Lien on the Underlying Properties. See The Trust Development Agreement and Drilling Support Lien beginning on page 45.

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 June 30, 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, 132 of the 172 horizontal wells drilled by the industry in the Colony Granite Wash to date, 129 of which are completed and the remaining three of which are awaiting completion and expected to be productive. Of the 132 horizontal wells drilled by Chesapeake in the Colony

Granite Wash, 124 are located in Washita County, in which the Underlying Properties are located. Chesapeake expects to operate

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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.

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 June 30, 2011, Chesapeake had nine drilling rigs operating in the Colony Granite Wash and owned or leased a total of 133 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 June 30, 2015 and is obligated to complete such drilling by June 30, 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 June 30, 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]				
	Oil (mbbl)	Natural Gas Liquids (mbbl)	Natural Gas (mmcf)	Total (mboe)	PV-10 Value[2] (In thousands)
Underlying Properties:					
Developed	2,648	7,791	75,689	23,054	343,504
Undeveloped	8,290	18,640	179,931	56,919	510,087
Total	10,938	26,431	255,620	79,973	853,591
Royalty Interests:					
Developed (90%)	2,233	6,235	60,536	18,557	325,434
Undeveloped (50%)	4,002	8,319	80,325	25,709	485,706
Total	6,235	14,554	140,861	44,266	811,140

(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 liquids and natural gas for the period from July 1, 2010 through June 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 and, for the royalty interests, costs of marketing services provided by Chesapeake affiliates, which will not be charged to the trust. The reference prices and the equivalent weighted average wellhead prices as of June 30, 2011 are presented in the table below.

	Oil (per bbl)	Natural gas liquids (per bbl)	Natural gas (per mcf)
Trailing 12-month average pricing	$ 89.86	$ 89.86	$ 4.21
Weighted average wellhead prices (Underlying Properties)	$ 86.08	$ 39.83	$ 2.93
Weighted average wellhead prices (royalty interests)	$ 86.09	$ 39.80	$ 2.86

(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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At the Termination Date, the estimated reserves attributable to the residual 50% interest in the royalty interests that the trust will own on the Termination Date and subsequently sell are 5.0 mmboe. The PV-10 value of such reserves calculated using 12-month trailing SEC pricing as of June 30, 2011 is $9.2 million.

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 July 1, 2011 effective date of the royalty interests and the timing of payments received by the trust for production in determining Target Distributions, the 2011 production forecast includes production from July 1, 2011 through November 30, 2011.

(2) Due to the June 30, 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 June 30, 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 liquids and natural gas 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 liquids and natural gas 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 liquids and natural gas 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 the trust s royalty interests in the Underlying Properties 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. The hedging counterparties may foreclose on their lien on the trust s royalty interests in certain circumstances.

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 liquids and natural gas, 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 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.

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Structure of the Trust

The following chart shows the relationship of Chesapeake, the trust and the public unitholders immediately following this offering (without giving effect to the exercise of the underwriters option to purchase additional common units).

* Chesapeake is expected to have an effective average net revenue interest of 29.0% in the Producing Wells and 39.0% 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 23.8% in the Producing Wells and 13.0% in the Development Wells.

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The Offering

Common units offered to public	22,875,000 common units (26,306,250 common units, if the underwriters exercise their option to purchase additional common units in full)
Trust units owned by Chesapeake after the offering	11,437,500 common units and 11,437,500 subordinated units (8,006,250 common units and 11,437,500 subordinated units, if the underwriters exercise their option to purchase additional common units in full)
Total units outstanding after the offering	34,312,500 common units and 11,437,500 subordinated units
Option to purchase additional common units	3,431,250 common units will be issued and retained by the trust at the initial closing, to be used to satisfy (if necessary) the 30-day option to purchase additional units granted to the underwriters. If the underwriters exercise their option to purchase additional common units, the trust will sell to the underwriters such number of the retained units as is necessary to satisfy the option to purchase additional common units, 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 underwriters do not exercise their option to purchase additional common units, 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 date of this prospectus. See The Trust Formation Transactions beginning on page 44.
Use of proceeds	The trust is offering the common units to be sold in this offering. Assuming no exercise of the underwriters option to purchase additional common units and an initial public offering price of $20.00 per common unit (the midpoint of the price range set forth on the cover page of this prospectus), the estimated net proceeds of this offering will be approximately $426.3 million, after deducting underwriting discounts and commissions, the structuring fee 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 and as partial consideration for the conveyance of the Perpetual Royalties. See The Trust Formation Transactions beginning on page 44.
	Chesapeake intends to use any proceeds it receives from the sale of the royalty interests to the trust 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

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	Use of Proceeds on page 42. Affiliates of certain of the underwriters are lenders under Chesapeake s credit facility and, in that respect, will receive a substantial portion of the proceeds from this offering through the repayment of borrowings outstanding under the facility. See Underwriting beginning on page 113.
NYSE symbol	CHKR
Trustee	The Bank of New York Mellon Trust Company, N.A.
Quarterly cash distributions	Quarterly cash distributions during the term of the trust will be made by the trustee approximately 60 days following the end of each calendar quarter to unitholders of record approximately 50 days following the end of each calendar quarter. The first distribution, which will cover the third quarter of 2011 (consisting of proceeds attributable to two months of production), is expected to be made on or about December 1, 2011 to record unitholders on or about November 21, 2011. The trustee intends to withhold $1.0 million from the first distribution to establish an initial cash reserve available for trust expenses. Thereafter, quarterly distributions will generally include royalties attributable to sales of oil, natural gas liquids and natural gas for three months, including the first two months of the quarter just ended and the last month of the quarter prior to that one.
	Actual cash distributions to the trust unitholders will fluctuate quarterly based on the quantity of oil, natural gas liquids and natural gas 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. The trust does not intend to hold annual meetings of the trust unitholders.

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Termination of the trust	The trust will dissolve and begin to liquidate on the Termination Date, which is June 30, 2031, and will soon thereafter wind up its affairs and terminate. At the Termination Date, the Term Royalties will revert automatically to Chesapeake. The Perpetual Royalties will be retained by the trust at the Termination Date and thereafter sold, and the net proceeds of the sale, as well as any remaining trust cash reserves, will be distributed to the unitholders 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 Royalty for the Producing Wells will and the Term Royalty for the Development Wells 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 Royalty for the Producing Wells will and the Perpetual Royalty for the Development Wells 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 beginning on page 95 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, 2014, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be approximately 55% 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 $0.55 per unit.
	Please read U.S. Federal Income Tax Considerations beginning on page 95 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 liquids and natural gas 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 liquids and natural gas production. Drilling for oil, natural gas liquids and natural gas 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 liquids and natural gas water or drilling fluids;

natural disasters;

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

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

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- reductions in oil, natural gas liquids and natural gas 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.

In addition, Development Wells may not be successful and Chesapeake is not obligated to drill replacement wells if this occurs. Under the Development Agreement, Chesapeake will receive credit for drilling a Development Well if the well is drilled in the AMI and perforated horizontally for completion in the Colony Granite Wash, even if such well does not successfully produce hydrocarbons. Additionally, once Chesapeake plugs and abandons an unsuccessful Development Well, that well will be released from the Drilling Support Lien.

Prices of oil, natural gas liquids and natural gas 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 liquids and natural gas. The markets for these commodities are very volatile. Oil, natural gas liquids and natural gas 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 liquids and natural gas;
- the price and level of foreign imports of oil, natural gas liquids and natural gas, 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 liquids and natural gas;
- weather conditions and seasonal trends;
- anticipated future prices of oil, natural gas liquids, natural gas, alternative fuels and other commodities;
- technological advances affecting energy consumption and energy supply;

- the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;
- natural disasters;
- 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 September 30, 2011, 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 September 30, 2011, the highest monthly NYMEX settled price was $13.11 per mmbtu and the lowest was $2.84 per mmbtu. In addition, the market price of oil, natural gas liquids and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil, natural gas liquids and natural gas for heating purposes during the winter season.

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Lower oil, natural gas liquids and natural gas prices will reduce proceeds to which the trust is entitled and may ultimately reduce the amount of oil, natural gas liquids and natural gas 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 liquids and natural gas 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 liquids and natural gas prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, 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 liquids and natural gas 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 liquids and natural gas 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 the trust s royalty interests in the Underlying Properties and may require the trust to make cash payments in excess of its receipts beginning on page 28.

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 Liquids and Natural Gas Reserves beginning on page 67 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 liquids and natural gas 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 liquids and natural gas based on factors and assumptions that include:

- historical production from the area compared with production rates from other producing areas;
- oil, natural gas liquids and natural gas 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 beginning on page 3.

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 liquids and natural gas 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 liquids and natural gas production is sold at prices consistent with settled NYMEX pricing for July through October 2011, monthly NYMEX forward pricing as of October 14, 2011 for the remainder of the period ending June 30, 2014 and assumed price increases after June 30, 2014 of 2.5% annually, capped at $120.00 per bbl of oil (which cap would be reached in 2026) and $7.00 per mmbtu of natural gas (which cap would be reached in 2028); 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 liquids and natural gas 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 beginning on page 20.

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 liquids and natural gas 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, 118 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 liquids and natural gas, 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 liquids and natural gas 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 service providers 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 liquids and natural gas, 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 liquids and natural gas 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 liquids and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil, natural gas liquids and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly 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 liquids and natural gas 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 liquids and natural gas 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 liquids and natural gas production from the Underlying Properties.

The amount of oil, natural gas liquids and natural gas 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 liquids and natural gas 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 liquids and natural gas 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 liquids and natural gas from, or future development of, the Underlying Properties.

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The oil, natural gas liquids and natural gas 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 liquids and natural gas from the Underlying Properties. The oil, natural gas liquids and natural gas reserves attributable to the Underlying Properties are depleting assets, which means that the reserves of oil, natural gas liquids and natural gas attributable to the Underlying Properties will decline over time. As a result, the quantity of oil, natural gas liquids and natural gas 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 liquids and natural gas. 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 liquids and natural gas 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 liquids and natural gas 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 liquids and natural gas and the benchmark price for oil, natural gas liquids and natural gas 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 beginning on page 56.

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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 liquids and natural gas (excluding costs of marketing services provided by Chesapeake);

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

- 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, costs associated with annual and quarterly reports to unitholders and certain internal expenses of the trust incurred pursuant to the registration rights agreement; and

- any amounts owed to counterparties under the trust s hedging arrangements.

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 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 beginning on page 50.

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 beginning on page 63. 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 the trust s royalty interests in the Underlying Properties 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 liquids hedging arrangements pursuant to which the trust will hedge approximately 50% of the expected oil and natural gas liquids production and 37% of the trust s expected revenues (based on NYMEX strip oil prices as of October 14,

2011) upon which the target distributions from October 1, 2011 through September 30, 2015 are based. Estimated production of natural gas liquids will be hedged using a conversion ratio of one barrel of natural gas liquids to 49.2% of a barrel of oil, which ratio may not be consistent with the market conversion ratio in the future. Except in limited circumstances involving the restructuring of an existing hedge, the remaining estimated production of oil and natural gas liquids and all production of natural gas from October 1, 2011 through September 30, 2015 will not be hedged and the trust will not have the ability to enter into additional hedges, terminate existing hedges or hedge production beyond September 30, 2015. With respect to unhedged volumes and periods, the trust will not be protected against the price risks inherent in holding interests in oil, natural gas liquids 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 liquids 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 duty to modify any of the trust s hedges except as required by the hedging arrangements, 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 hedge counterparties. If any of the counterparties to the oil and natural gas liquids 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 liquids prices.

If actual production, over which the trust has no control, is below the amounts forecast in the reserve reports and oil or natural gas liquids 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 the hedge 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 and Chesapeake s obligations to the counterparties under the hedging arrangements will be secured by the trust s royalty interests in the Underlying Properties. Subject to any applicable notice and cure periods, if, among other things, the trust or Chesapeake is in material default of the drilling, payment or reporting obligations set forth in the hedging arrangements, or becomes subject to bankruptcy proceedings or the trust becomes subject to certain change of control transactions, the hedging counterparties may foreclose on the lien on the trust s royalty interests in the Underlying Properties. Following foreclosure by the hedging counterparties, the counterparties may not be able to secure a replacement operator and any amounts recovered in such foreclosure action would not result in any distribution to the trust unitholders. In addition, the trust s hedging arrangements will contain a prohibition on the trust granting additional liens on any of its properties, other than customary permitted liens and liens in favor of the trustees of the trust.

Please see The Trust Hedging Arrangements beginning on page 47 for more details on the prices, production volumes and events of default 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 described in Description of the Trust Agreement Duration of the Trust; Sale of Royalty Interests on page 87. 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.

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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 depend, among other things, on the prices of oil, natural gas liquids and natural gas at that time. There can be no assurance that the prices of oil, natural gas liquids and natural gas 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 beginning on page 44.

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 liquids and natural gas prices, current and prospective conditions in the supply and demand for oil, natural gas liquids and natural gas, 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, and the trust does not currently anticipate holding annual meetings. Likewise, there is no requirement 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 prohibit recovery of certain types of damages, such as consequential and punitive damages, and 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.

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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.

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 11,437,500 common units (assuming no exercise by the underwriters of their option to purchase additional common units) and 11,437,500 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 beginning on page 113. 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 on page 93.

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 liquids and natural gas production to decline at a faster rate and thereby result in lower cash distributions by the trust in the future.

Following the satisfaction of its drilling obligation to the trust, Chesapeake may, without the consent or approval of the trust unitholders, sell all or any part of its retained interest in the Underlying Properties, if the Underlying Properties are sold subject to and burdened by the royalty interests. Although Chesapeake must require any purchaser of its retained interest in the Underlying Properties to assume Chesapeake s obligations with respect to those properties, such sale may not be in the best interests of the trust and the trust unitholders. Any purchaser may lack Chesapeake s experience in the Colony Granite Wash or its creditworthiness. See After satisfying its drilling obligation to the trust, Chesapeake may sell all or a portion of its retained interest in the Underlying Properties, subject to and burdened by the royalty interests; any such purchaser could have a weaker financial position and/or be less experienced in oil, natural gas liquids and natural gas development and production than Chesapeake beginning on page 32 and Description of the Royalty Interests Additional Features of the Royalty Interests Sale and Release of Underlying Properties on page 81.

Following the satisfaction of its drilling obligation to the trust, Chesapeake may, without the consent or approval of the trust unitholders, require the trust to release royalty interests with an aggregate value of up to $5.0 million during any 12-month period in connection with a sale by Chesapeake of a portion of its retained interest in the Underlying Properties. Although these releases are conditioned upon the trust receiving an amount equal to the fair value to the trust of such royalty interests, the fair value received by the trust for such royalty interests may not fully compensate the trust for the value of future production attributable to the royalty interests disposed of. See Description of the Royalty Interests Additional Features of the Royalty Interests Sale and Release of Underlying Properties on page 81.

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. Chesapeake could favor the interests of these affiliates to the detriment of the trust and trust unitholders.

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 expenses as they become due, 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.

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

You will not be entitled to vote on any sale by Chesapeake of its retained interest in 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, including Chesapeake s obligation to operate the Underlying Properties sold in accordance with the Reasonably Prudent Operator Standard and Chesapeake s true-up obligations with respect to the Underlying Properties sold, and Chesapeake would have no continuing obligation to the trust for those properties. Additionally, after satisfying its drilling obligation, Chesapeake may enter into farmout or participation arrangements with respect to the wells burdened by the trust s royalty interests. Any purchaser, farmout counterparty or participating partner could have a weaker financial position and/or be less experienced in oil, natural gas liquids and natural gas development and production in the Colony Granite Wash than Chesapeake, which could result in a decrease in production from the Underlying Properties sold and a corresponding decrease in cash available for distribution to the trust s unitholders. Additionally, in the event that Chesapeake enters into such a farmout or participation agreement, the royalty interest will not burden any interests that the counterparty earns under such an agreement.

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 Chesapeake s bankruptcy, it may be expensive and time-consuming for the trust to exercise its remedies and the trust may be treated as an unsecured creditor of Chesapeake.

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 94% of the Producing Wells. The conveyances provide that Chesapeake will be obligated to market, or cause to be marketed, the oil,

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natural gas liquids and natural gas 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 liquids and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake s control. See Chesapeake Energy Corporation on page 43 and Where You Can Find More Information beginning on page 117 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, file a lawsuit to collect money damages from Chesapeake and pursue other available legal remedies against Chesapeake. However, the trust is not permitted to obtain specific performance from Chesapeake of its drilling obligation, and the maximum amount the trust can recover in a foreclosure or other action is limited to approximately $262.7 million, which is the estimated amount of the trust s share of the costs of drilling the Development Wells and is not indicative of the total costs that will actually be incurred in drilling those wells. The maximum amount that the trust can recover will be reduced proportionately as each Development Well is completed and released from the Drilling Support Lien and will not be adjusted for general inflation or inflation in oilfield service costs. 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 within a reasonable period of time. As long as the trust s royalty interests are pledged as collateral to the trust s hedge counterparties, the trust s 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 royalty interests by the hedging counterparties. The possibility of this foreclosure could deter the trust from exercising its right to foreclose on the Drilling Support 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 liquids and natural gas at the same prices as Chesapeake was able to achieve.

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In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that will convey the royalty interests to the trust, the trust could lose the value of all of the royalty interests if a bankruptcy court were to hold that the royalty interests constitute an asset of the bankruptcy estate. Chesapeake and the trust believe that the royalty interests would not be included in any such bankruptcy estate because the recordation of the conveyance of the royalty interests in the appropriate real property records in Oklahoma will constitute the conveyance of fully vested real property interests under Oklahoma law or interests in hydrocarbons in place or to be produced under Oklahoma law. Oklahoma law, however, is not entirely clear as to whether an overriding royalty interest is a real property interest. While the Oklahoma Supreme Court has recently held that royalty interests are real property interests, such cases did not expressly overturn prior Oklahoma Supreme Court cases holding that an overriding royalty interest was not necessarily a real property interest. In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that will convey the royalty interests to the trust, if a bankruptcy court held that (a) the royalty interests did not constitute fully vested real property interests or interests in hydrocarbons in place or to be produced or (b) the royalty interests were not otherwise eligible to be excluded from the bankruptcy estate under federal bankruptcy law, the royalty interests may be treated as unsecured claims of the trust against Chesapeake. If that were the case, creditors of Chesapeake would be able to claim the royalty interests as an asset of the bankruptcy estate to be sold to satisfy obligations to them and the trust could lose the entire value of the royalty interests to senior creditors of Chesapeake.

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 liquids and natural gas 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 non-operated properties, Chesapeake is dependent on the operator for operational and regulatory compliance. See The Underlying Properties Regulation beginning on page 75 for a discussion of environmental regulation applicable to Chesapeake.

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Chesapeake maintains policies of insurance that it believes are customary in the industry, including a $75 million control of well policy that insures against certain sudden and accidental risks associated with drilling, completing (including hydraulic fracturing) and operating its wells. Chesapeake also carries a $425 million comprehensive general liability umbrella policy and a $150 million pollution liability policy. Chesapeake s insurance policies provide for customary deductibles (generally ranging from $1.0 million to $5.0 million), and there is no assurance that these policies will provide complete coverage against all operational risks. In addition, these policies do not cover penalties or fines that may be assessed by a governmental authority. If Chesapeake experiences any of the problems described above and its insurance policies do not provide adequate coverage, its ability to conduct operations and perform its obligations to the trust could be adversely affected. Moreover, these policies also cover properties and operations of Chesapeake unrelated to the Underlying Properties and the trust. To the extent proceeds from such policies are used to cover losses in Chesapeake s other operations, such coverage may not be available to cover losses relating to the trust. Finally, we are not obligated to the trust to maintain any particular types or amounts of insurance, and insurance may not be commercially available at the levels indicated above at all times during the life of the trust. If a well is damaged, Chesapeake would have no obligation to drill a replacement well or otherwise compensate the trust 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 liquids and natural gas, 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 Oil and Natural Gas

Federal budget proposals would potentially increase and accelerate the payment of federal income taxes of producers of oil and natural gas. 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 oil and natural gas 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 currently used in completing greater than 90% of all oil and natural gas wells drilled 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 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 liquids and natural gas 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 liquids and natural gas. 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 liquids and natural gas.

For more information on environmental and regulatory risks, please read The Underlying Properties Regulation beginning on page 75.

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 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 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 U.S. federal income tax treatment of the Development Royalty Interest is not entirely free from doubt. A successful challenge by the IRS to the tax position the trust takes with respect to the Development Royalty Interest could affect the amount, timing and character of income, gain or loss relating to an investment in trust units.

The U.S. federal income tax laws and precedents applicable to the tax treatment of royalty interests in wells that will be drilled in the future are not well established. As a result, the tax treatment of the Development Royalty Interest is not entirely free from doubt. A successful challenge by the IRS to the tax position the trust takes with respect to the Development Royalty Interest could negatively affect the amount, timing and character of income, gain or loss relating to a unitholder s investment in trust units, which could increase or accelerate the amount of federal income tax payable on a unitholder s share of the trust s income. Please read U.S. Federal Income Tax Considerations Tax Classification of the PDP Royalty Interest and the Development Royalty Interest beginning on page 98.

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 liquids and natural gas attributable to the trust will be approximately 2.0% 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.

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

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

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

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 beginning on page 106 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.

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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 on page 105.

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 on page 107.

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

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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 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 liquids and natural gas 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 liquids and natural gas 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 liquids and natural gas 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 beginning on page 50, 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, 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 beginning on page 20, 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 option to purchase additional common units and an initial public offering price of $20.00 per common unit (the midpoint of the price range set forth on the cover page of this prospectus), the estimated net proceeds of this offering will be approximately $426.3 million, after deducting underwriting discounts and commissions, the structuring fee 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 and as partial consideration for the conveyance of the Perpetual Royalties. The following table summarizes the trust s sources and uses of funds associated with this offering (based on the foregoing assumptions):

Sources:	
Proceeds to trust from sale of common units in this offering	$ 457,500,000
Total	$ 457,500,000
Uses:	
Underwriting discounts and commissions	$ 26,306,250
Structuring fee paid to Morgan Stanley & Co. LLC and Raymond James & Associates, Inc.	2,287,500
Offering expenses	2,571,922
Partial consideration for the purchase of royalty interests from Chesapeake	426,334,328
Total	$ 457,500,000

At the initial closing, 3,431,250 common units that may be issued to Chesapeake will be retained by the trust to satisfy (if necessary) the option to purchase additional common units granted to the underwriters. If the underwriters exercise their option to purchase additional common units, the trust will sell to the underwriters such number of the retained units as is necessary to satisfy the option to purchase additional common units, and will then deliver the net proceeds of such sale, together with any remaining unsold units, to Chesapeake as partial consideration for the conveyance of the Perpetual Royalties. If the option to purchase additional common units is not exercised by the underwriters, the retained units will be delivered to Chesapeake as partial consideration for the conveyance of the Perpetual Royalties promptly following the 30th day after the date of this prospectus.

Chesapeake intends to use any proceeds it receives from the sale of the royalty interests to the trust 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 substantial portion of the proceeds from this offering through the repayment of borrowings outstanding under the facility. See Underwriting beginning on page 113. Chesapeake s credit facility matures on December 2, 2015 and, as of September 30, 2011, the weighted average interest rate applicable to borrowings under the credit facility was 1.98%. 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, Frontier, Codell, Bakken/Three Forks and Utica unconventional liquids plays. It has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. As of June 30, 2011, Chesapeake had total assets of approximately $36.7 billion and total estimated net proved reserves of 16.5 tcfe. Chesapeake has approximately 61,100 net acres leased in the Colony Granite Wash and as of June 30, 2011, Chesapeake was operating nine rigs in the Colony Granite Wash.

Chesapeake has not previously sponsored a royalty trust.

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 operations 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 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 trustee has no current plans to authorize the trust to borrow money.

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 $1.0 million per year, although such costs could be greater or less depending on future events that cannot be predicted. Included in the annual estimate is an annual administrative fee of $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 an initial cash reserve available for trust expenses. Additional cash reserves may also be established from time to time as determined by the trustee to pay future expenses of the trust.

Formation Transactions

At or prior to the closing of the offering, Chesapeake will convey 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 July 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 liquids and natural gas 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 July 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 liquids and natural gas 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 liquids and natural gas 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 July 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 liquids and natural gas 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, and 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 to the trust. The Term Royalties will be conveyed to a wholly owned subsidiary of Chesapeake in exchange for a demand note, such subsidiary will convey the Term Royalties to the trust in exchange for a portion of the net proceeds of this offering in an amount equal to such demand note and such subsidiary will use such proceeds to repay the demand note. In exchange for the Perpetual Royalties, the trust will issue to Chesapeake 11,437,500 common units and 11,437,500 subordinated units and will also deliver to Chesapeake the balance of the net proceeds of the offering. See Use of Proceeds on page 42.

The trust will retain 3,431,250 common units at the initial closing, to be used to satisfy (if necessary) the option to purchase additional common units granted to the underwriters. If the underwriters exercise their option to purchase additional common units, the trust will sell to the underwriters such number of the retained units as is necessary to satisfy the option to purchase additional common units, and will then deliver the net proceeds of such sale, together with any remaining unsold units, to Chesapeake as partial consideration for the conveyance of the Perpetual Royalties. If the underwriters do not exercise the option to purchase additional common units, the retained units will be delivered to Chesapeake as partial consideration for the conveyance of the Perpetual Royalties, promptly following the 30th day after the date of this prospectus.

The trust will sell the 22,875,000 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 on page 92. 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 June 30, 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 following the Termination Date, 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 on page 77. 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 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 AMI by June 30, 2015 and is obligated to complete such drilling by June 30, 2016. Chesapeake will grant to the trust the Drilling Support Lien, covering Chesapeake s retained 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 maximum amount that may be obtained by

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the trust pursuant to the Drilling Support Lien or through its exercise of other remedies against Chesapeake for failure to meet its drilling obligation may not exceed $262.7 million. As Chesapeake fulfills its drilling obligation over time, Development Wells that are completed or that are perforated for completion and then plugged and abandoned will be released from the Drilling Support Lien and the total dollar amount that may be recovered by the trust for breach of the drilling obligation will be proportionately reduced.

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 52.0%.

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 52.0%, Chesapeake will receive credit for such well in the proportion that its net revenue interest in the well bears to 52.0%.

Accordingly, for example, if Chesapeake drilled one well in which it has a 80% net revenue interest, and such well were perforated to a length of 3,500 feet, such well would count for purposes of the development agreement as 1.54 Development Wells (i.e., 3,500/3,500 x 80%/52.0%). 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 0.82 Development Wells (i.e., 3,000/3,500 x 50%/52.0%).

Given that Chesapeake s actual net revenue interest in each Development Well may be greater than or less than 52.0% 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 118 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 drilling, 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. If Chesapeake is unable to successfully complete a Development Well, Chesapeake is obligated to plug and abandon such well to the extent required by law.

Chesapeake will receive credit for drilling a Development Well if the well is drilled in the AMI and perforated horizontally for completion in the Colony Granite Wash, even if such well does not successfully produce hydrocarbons. Additionally, if Chesapeake perforates a Development Well for completion and then plugs and abandons that well, it will be released from the Drilling Support Lien.

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 118 Development Wells with the same completion technique as the 69 Producing Wells. These 69 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 69 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.

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 covering a portion of the trust s oil and natural gas liquids production through September 30, 2015. 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. Any payment due from or required to be made to such counterparties will be paid by the 40th day following the end of the calendar quarter in which such payments become due. 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 and natural gas liquids prices.

Chesapeake will have authority, in its role as hedge manager to the trust, to terminate, restructure or otherwise modify all or any portion of the trust s hedging arrangements to the extent that Chesapeake reasonably determines, acting in good faith, that the oil and natural gas liquids volumes hedged under such portion of the contracts exceed, or are expected to exceed, the combined estimated oil and natural gas liquids production attributable to the trust s royalty interests over the periods hedged. The counterparties may require Chesapeake to terminate, restructure or otherwise modify the hedging arrangements if Chesapeake does not drill a specified number of Development Wells in each six-month period ending June 30 or December 31 during the term of the hedging arrangements and the counterparties determine that the oil and natural gas liquids volumes hedged under such portion of the contracts exceed, or are expected to exceed, the combined estimated oil and natural gas liquids production attributable to the trust s royalty interests over the periods hedged. Except in such limited circumstances, the trust will not have the ability to enter into additional hedges and, accordingly, after the expiration of the hedging arrangements at the end of the third quarter of 2015, no production will be hedged. For more information on Chesapeake s role as hedge manager for the trust, please see Administrative Services Agreement on page 49.

Under the hedging arrangements and separate from the drilling obligation under the development agreement, Chesapeake will be required to drill and complete, or cause to be drilled and completed, a specified

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number of Development Wells by the end of each six-month period ending June 30 and December 31 during the term of the hedging arrangements. In addition, with respect to each such six-month period, the trust will be required to deliver to the counterparties and the collateral agent under the hedging arrangements (a) an independent reserve engineers report that sets forth the total reserves estimated to be attributable to the trust s interest in the Underlying Properties as of the end of such period and such other information as is typically included in, or required under SEC rules to be included in, summary reserve engineers reports and (b) a report that sets forth certain information regarding the Development Wells drilled and completed as of the end of such six-month period.

The trust s and Chesapeake s obligations to the counterparties under the hedging arrangements will be secured by the trust s royalty interests in the Underlying Properties. Subject to any applicable notice and cure periods, if, among other things, the trust or Chesapeake is in material default of the drilling, payment or reporting obligations under the hedging arrangements or becomes subject to bankruptcy proceedings or the trust becomes subject to certain change of control transactions, the hedging counterparties may foreclose on the lien on the trust s royalty interests in the Underlying Properties. In addition, the trust s hedging arrangements will contain a prohibition on the trust granting additional liens on any of its properties, other than customary permitted liens and liens in favor of the trustees of the trust. Under the trust agreement, the trustee may create a cash reserve to pay for future expenses of the trust.

Under the hedging arrangements, the trust will hedge approximately 50% of the expected oil and natural gas liquid production and 38% of the expected revenues (based on NYMEX strip oil prices as of October 14, 2011) upon which the target distributions from October 1, 2011 through September 30, 2015 are based. Estimated production of natural gas liquids will be hedged with oil contracts using a conversion ratio of one barrel of natural gas liquids to 49.2% of a barrel of oil. The remaining estimated production of oil and natural gas liquids during that time, all production of natural gas during that time and all production after such time will not be hedged, except in connection with the restructuring of an existing hedge. The trust s hedging arrangements will not be qualified for hedge accounting treatment, and therefore all future mark-to-market fluctuations will be recorded to the statement of operations.

The following tables illustrate the application of oil swaps between oil and natural gas liquids production, notional amount and weighted average fixed price for the hedging arrangements into which the trust will enter.

	Volume (mbbl)	Weighted Average Price (per bbl)
Oil:		
Q4 2011	89.7	$ 84.37
Q1 2012	89.2	84.99
Q2 2012	91.4	85.71
Q3 2012	97.2	86.40
Q4 2012	102.3	86.98
Q1 2013	99.4	87.37
Q2 2013	101.1	87.60
Q3 2013	104.1	87.79
Q4 2013	101.6	87.99
Q1 2014	97.7	88.08
Q2 2014	96.3	88.21
Q3 2014	97.1	88.34
Q4 2014	95.0	88.45
Q1 2015	92.5	88.59
Q2 2015	95.3	88.76
Q3 2015	80.6	88.90
Total Oil	1530.5	$ 87.42

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	Volume (mbbl)	Weighted Average Price (per bbl)
Natural Gas Liquids:		
Q4 2011	150.1	$ 41.50
Q1 2012	151.4	41.80
Q2 2012	153.4	42.16
Q3 2012	161.5	42.50
Q4 2012	169.1	42.79
Q1 2013	168.3	42.98
Q2 2013	169.0	43.09
Q3 2013	170.5	43.18
Q4 2013	167.8	43.28
Q1 2014	167.1	43.33
Q2 2014	170.8	43.39
Q3 2014	166.0	43.46
Q4 2014	161.1	43.51
Q1 2015	159.7	43.58
Q2 2015	162.9	43.66
Q3 2015	148.5	43.73
Total Natural Gas Liquids	2597.2	$ 43.01

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 have authority to terminate, restructure or otherwise modify all or any portion of the trust s hedging arrangements to the extent that Chesapeake reasonably determines, acting in good faith, that the oil and natural gas liquids volumes hedged (taken together, using a per barrel conversion ratio of natural gas liquids to oil of 49.2%) under such portion of the contracts exceed, or are expected to exceed, the combined estimated oil and natural gas liquids production attributable to the trust s royalty interests over the periods hedged. However, in fulfilling its role as hedge manager, Chesapeake will not act as a fiduciary for the trust and will have no affirmative duty to modify any of the trust s hedges, except as required by the hedging arrangements. Moreover, under the trust agreement, 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 been wound 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 liquids and natural gas 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 liquids and natural gas 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 liquids and natural gas 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 liquids and natural gas prices received;
- the volume of oil, natural gas liquids and natural gas produced and sold;
- amounts realized and paid under hedging arrangements;
- post-production expenses and any applicable taxes; and
- the trust s expenses.

Chesapeake has established quarterly target levels of cash distributions for the life of the trust. Such target distribution levels are set forth on Annex B to this prospectus. The target distributions were prepared by Chesapeake on a cash basis based on assumptions regarding production volumes, pricing and other assumptions that are described below in Significant Assumptions Used to Calculate the Target Distributions beginning on page 56. The production forecasts are estimates prepared by Ryder Scott and have been used to calculate target distributions. Actual cash distributions to the trust unitholders will fluctuate quarterly based on quantity of oil, natural gas liquids and natural gas produced from the Underlying Properties, the prices received for such production, payments under the hedge arrangements, the trust s administrative expenses and other factors. Chesapeake will pay to the trust each quarter an amount equal to the trust s royalty interest in the proceeds of production from the Underlying Properties received during the calendar quarter most recently ended (after deducting post-production expenses and any applicable taxes). The trust, in turn, will make quarterly cash distributions of substantially all of its quarterly cash receipts, after deducting the trust s expenses, to holders of trust units approximately 60 days following the end of each quarter through and including the quarter ending June 30, 2031.

The first distribution, which will cover the third quarter of 2011, is expected to be made on or about December 1, 2011 to record unitholders on or about November 21, 2011. The trustee intends to withhold $1.0 million from the first distribution to establish an initial cash reserve available for trust expenses. If the trustee uses such cash reserve to pay for trust expenses, the reserve must be replenished before any further quarterly distributions are made to trust unitholders. Additional cash reserves may also be established from time to time as determined by the trustee to pay future expenses of the trust. Due to the timing of the payment of production proceeds to the trust, the trust expects that the first distribution will include royalties attributable to sales for oil, natural gas liquids and natural gas for two months (July and August 2011). Thereafter, quarterly distributions will generally include royalties attributable to sales of oil, natural gas liquids and natural gas for three months, including the first two months of the quarter just ended and the last month of the quarter prior to that one. Because payments to the trust will be generated by depleting assets and production from the Underlying Properties will diminish over time, a portion of each distribution will represent a return of your original investment.

In order to provide support for cash distributions on the common units, Chesapeake has agreed to subordinate 11,437,500 of the trust units it will retain following this offering, which will constitute 25% of the

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outstanding trust units. The subordinated units will be entitled to receive pro rata distributions from the trust if and to the extent there is sufficient cash to provide a cash distribution on the common units that is no less than the applicable quarterly subordination threshold. If there is insufficient cash to fund such a distribution on all trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. Each applicable quarterly subordination threshold is 20% below the target distribution level for the corresponding quarter, as reflected on Annex B. In exchange for agreeing to subordinate these trust units, and in order to provide additional financial incentive to Chesapeake to perform its drilling obligation and 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 during the subordination period exceeds the target distribution for such quarter by more than 20%. Chesapeake s right to receive incentive distributions will terminate upon the expiration of the subordination period.

The subordinated units will automatically convert into common units on a one-for-one basis and Chesapeake s right to receive incentive distributions will terminate at the end of the fourth full calendar quarter following Chesapeake s satisfaction of its drilling obligation to the trust. Chesapeake currently intends to complete its drilling obligation on or before June 30, 2015 and accordingly, Chesapeake expects the subordinated units will convert into common units on or before June 30, 2016. Chesapeake is obligated to complete its drilling obligation by June 30, 2016, in which event the subordinated units would convert into common units on or before June 30, 2017.

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 below. The accompanying prospective financial information was not prepared with a view toward complying with the regulations of the SEC or the guidelines established by the American Institute of Certified Public Accountants with respect to preparation and presentation of prospective financial information. More specifically, such information omits items that are not relevant to the trust, such as changes in financial position, an earnings per unit measure and certain non-cash expenses for depreciation, depletion and amortization used to arrive at a GAAP net income measure. 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.

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 historical 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 second quarter of 2017. The effective date of the conveyance of the royalty interests is July 1, 2011, which means that the trust will receive credit for 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.

Period	Subordination Threshold(1)	Target Distribution (per unit)	Incentive Threshold(1)
2011:			
Third Quarter(2)	$ 0.37	$ 0.46	$ 0.55
Fourth Quarter	0.56	0.70	0.85
2012:			
First Quarter	0.59	0.74	0.89
Second Quarter	0.61	0.76	0.91
Third Quarter	0.63	0.79	0.95
Fourth Quarter	0.68	0.85	1.02
2013:			
First Quarter	0.70	0.87	1.05
Second Quarter	0.70	0.87	1.05
Third Quarter	0.72	0.90	1.08
Fourth Quarter	0.70	0.88	1.05
2014:			
First Quarter	0.70	0.88	1.06
Second Quarter	0.69	0.86	1.04
Third Quarter	0.70	0.87	1.05
Fourth Quarter	0.67	0.84	1.00
2015:			
First Quarter	0.67	0.84	1.00
Second Quarter	0.69	0.86	1.03
Third Quarter	0.65	0.81	0.97
Fourth Quarter	0.56	0.70	0.84
2016:			
First Quarter	0.51	0.64	0.77
Second Quarter	0.47	0.59	0.71
Third Quarter	0.44	0.55	0.66
Fourth Quarter	0.42	0.52	0.62
2017:			
First Quarter	0.39	0.49	0.59
Second Quarter	0.38	0.47	0.56

(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 two months of actual production from July and August 2011, and gives effect to the establishment of a $1.0 million reserve for trust expenses withheld by the trustee.

Chesapeake has prepared the operational and financial information set forth above and below in order to present the target distributions attributable to the oil, natural gas liquids and natural gas sales volumes reflected in the reserve reports included as Annex A to this prospectus. The target distributions, in the view of Chesapeake s management, were prepared on a reasonable basis based on the assumptions outlined in Significant Assumptions Used to Calculate the Target Distributions beginning on page 56.

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

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

Cash distributions to trust unitholders will be particularly sensitive to fluctuations in oil, natural gas liquids and natural gas prices and production volumes. See Sensitivity of Target Distributions to Changes in Oil, Natural Gas Liquids and Natural Gas Prices and Volumes beginning on page 61, which shows estimated effects to cash distributions through June 30, 2012 from changes in assumed realized oil, natural gas liquids and natural gas prices as well as changes in estimated production volumes. As a result of typical production declines for oil, natural gas liquids and natural gas properties, production estimates generally decrease from year to year. However, the production estimates included in the table below reflect that these declines are expected to be offset by additional production from Development Wells as they are completed and begin to produce. The timing of the completion of, and the amount of production attributable to, the Development Wells are substantially dependent on Chesapeake executing its drilling plans with respect to the drilling and completion of the Development Wells in a manner substantially similar to those underlying the assumptions used in establishing these target distributions. In addition, the completion of Chesapeake s drilling obligation will depend, in part, on the completion of drilling for certain Development Wells by third parties, over whom Chesapeake has no control, in a manner consistent with the assumptions used in establishing these target distributions. Please see Risk Factors beginning on page 20 for risks relating to the timing of drilling and amount of production attributable to the Development Wells. **As a result of these factors, the target distributions shown in the tables below are not necessarily indicative of the actual distributions for future years.**

Because payments to the trust will be generated by depleting assets and production from the Underlying Properties will diminish over time, a portion of each distribution will represent a return of your original investment. See Risk Factors The oil, natural gas liquids and natural gas 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 on page 27.

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The table below presents the calculation of the target distributions for each quarter through and including the quarter ending June 30, 2012.

Period	Three Months Ending September 30, 2011(1)	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)	103	178	181	181
Natural gas liquids sales volumes (mbbls)	179	299	302	304
Natural gas sales volumes (mmcf)	1,720	2,876	2,909	2,923
Total sales volumes (mboe)	569	956	967	972
% PDP sales volumes	100%	84%	69%	61%
% PUD sales volumes		16%	31%	39%
% Oil volumes	18%	19%	19%	19%
% Natural gas liquids volumes	32%	31%	31%	31%
% Natural gas volumes	50%	50%	50%	50%
Commodity price and derivative contract positions				
NYMEX futures price(2)				
Oil ($/bbl)	$ 95.93	$ 86.03	$ 87.10	$ 87.35
Natural gas liquids ($/bbl)	$ 47.15	$ 42.31	$ 42.85	$ 42.97
Natural gas ($/mmbtu)	$ 4.36	$ 3.78	$ 4.06	$ 4.07
Assumed realized weighted unhedged price(3)				
Oil ($/bbl)	$ 92.35	$ 82.45	$ 83.52	$ 83.77
Natural gas liquids ($/bbl)	$ 44.76	$ 40.01	$ 40.46	$ 40.45
Natural gas ($/mcf)	$ 3.12	$ 2.48	$ 2.81	$ 2.98
Assumed realized weighted hedged price(4)				
Oil ($/bbl)	$ 92.35	$ 81.56	$ 82.34	$ 82.83
Natural gas liquids ($/bbl)	$ 44.76	$ 39.57	$ 39.88	$ 39.99
Percent of oil volumes hedged		33.1%	49.9%	50.0%
Oil hedged price ($/bbl)	$	$ 84.18	$ 84.74	$ 85.48
Percent of natural gas liquids volumes hedged		33.6%	50.0%	50.0%
Natural gas liquids hedged price ($/bbl)	$	$ 41.41	$ 41.68	$ 42.05
Estimated cash available for distribution				
Oil sales revenues	$ 9,554	$ 14,648	$ 15,083	$ 15,175
Natural gas liquids sales revenues	8,030	11,953	12,220	12,278
Natural gas sales revenues	5,358	7,120	8,172	8,707
Realized gains (losses) from derivative contracts		(289)	(389)	(309)
Operating revenues and realized gains (losses) from derivative contracts	22,942	33,432	35,085	35,851
Production taxes	(726)	(935)	(938)	(930)
Trust administrative expenses(5)	(1,327)	(250)	(250)	(250)
Total trust expenses	(2,053)	(1,185)	(1,188)	(1,180)
Cash available for distribution	$ 20,890	$ 32,247	$ 33,896	$ 34,670
Trust units outstanding	45,750	45,750	45,750	45,750
Target distribution per trust unit	$ 0.46	$ 0.70	$ 0.74	$ 0.76

Subordination threshold per trust unit	$ 0.37	$ 0.56	$ 0.59	$ 0.61
Incentive threshold per trust unit	$ 0.55	$ 0.85	$ 0.89	$ 0.91

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Period	September 30, 2011[(1)]	December 31, 2011[(1)]	March 31, 2012[(1)]	June 30, 2012[(1)]
	Three Months Ending			
	(In thousands, except volumetric and per unit data)			
If actual cash exceeds targeted by 20%	$ 25,068	$ 38,696	$ 40,676	$ 41,604
Cash necessary to meet incentive threshold	25,068	38,696	40,676	41,604
Excess cash available for incentive distributions				
Distributions to unitholders				
Incentive distributions to Chesapeake				
If actual cash available exceeds targeted by 40%	$ 29,246	$ 45,146	$ 47,455	$ 48,539
Cash necessary to meet incentive threshold	25,068	38,696	40,676	41,604
Excess cash available for incentive distributions	4,178	6,449	6,779	6,934
Distributions to unitholders	2,089	3,225	3,390	3,467
Incentive distributions to Chesapeake	2,089	3,225	3,390	3,467
If actual cash available falls short of projected by 20%	16,712	25,798	27,117	27,736
Cash available for distribution to common units	12,534	19,348	20,338	20,802
Cash necessary to meet common unit subordination threshold	12,534	19,348	20,338	20,802
Cash short of subordination threshold				
Reduction in distribution to subordinated units to support subordination threshold				
Cash distributions to common unitholders	12,534	19,348	20,338	20,802
Cash distributions to subordinated units	$ 4,178	$ 6,449	$ 6,779	$ 6,934
If actual cash available falls short of projected by 40%	12,534	19,348	20,338	20,802
Cash available for distribution to common units	9,400	14,511	15,253	15,602
Cash necessary to meet common unit subordination threshold	12,534	19,348	20,338	20,802
Cash short of subordination threshold	(3,133)	(4,837)	(5,084)	(5,201)
Reduction in distribution to subordinated units to support subordination threshold	3,133	4,837	5,084	5,201
Cash distributions to common unitholders	$ 12,534	$ 19,348	$ 20,338	$ 20,802
Cash distributions to subordinated units				

(1) The three months ending September 30, 2011 include proceeds attributable to the first two months of production from July 1, 2011 to August 31, 2011. Thereafter, quarterly distributions will generally include royalties attributable to sales of oil, natural gas liquids and natural gas for three months, including the first two months of the quarter just ended and the last month of the quarter prior to that one.

(2) Average NYMEX settled and futures prices, as reported October 14, 2011. For a description of the effect of lower NYMEX prices on target cash distributions, see Sensitivity of Target Distributions to Changes in Oil, Natural Gas Liquids and Natural Gas Prices and Volumes beginning on page 61.

(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 Significant Assumptions Used to Calculate the Target Distributions beginning on page 56.

(4) No hedging arrangements will cover natural gas.

(5) Includes the establishment of an initial cash reserve of $1.0 million for trust expenses in period ending September 30, 2011.

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Unaudited Pro Forma Distributable Income

If the conveyance of the royalty interests and the closing of this offering had taken place on January 1, 2010, pro forma distributable income of the trust for the year ended December 31, 2010 would have been $153.0 million or $3.34 per trust unit. This amount would have been sufficient to pay the aggregate target distributions for the four quarters ending September 30, 2012 of $2.99 per trust unit. If the conveyance of the royalty interests and the closing of this offering had taken place on January 1, 2011, pro forma distributable income of the trust for the six months ended June 30, 2011 would have been $72.8 million or $1.59 per trust unit. This amount would have been sufficient to pay the aggregate target distributions for the two quarters ending March 31, 2012 of $1.44 per trust unit. For a calculation of the pro forma distributable income of the trust for these periods, please read Chesapeake Granite Wash Trust Unaudited Pro Forma Statement of Distributable Income on page F-16.

Significant Assumptions Used to Calculate the Target Distributions

In preparing the target distributions and subordination and incentive threshold tables above and sensitivity tables below, the revenues and expenses of the trust were calculated based on the terms of the conveyances creating the trust s royalty interests using the following assumptions and those set forth above under Target Distributions and Subordination and Incentive Thresholds beginning on page 50. These estimations are described under Description of the Royalty Interests beginning on page 78.

Production Estimates. As more fully described in the reserve report, our forecasts of future production rates are based on historical performance data for the Producing Wells, and test data and other related information was used to estimate the anticipated initial production rates for the Development Wells. The estimates of reserves and production relating to the Underlying Properties and the royalty interests included in the reserve reports have been made in accordance with the SEC s rules for reserve reporting, including historical pricing. The estimated production in the forecast period gives effect to Chesapeake s drilling schedule of approximately 30 wells each year.

Oil Prices. The assumed unhedged oil prices utilized for purposes of preparing the target distributions are based on settled NYMEX pricing for July through October 2011, NYMEX forward pricing for the remainder of the period ending June 30, 2014 and assumed price increases after June 30, 2014 of 2.5% annually, capped at $120.00 per bbl of oil. Using these assumptions, the price per bbl of oil would reach the $120.00 cap in 2026. These prices are higher than the SEC-mandated pricing used in the reserve reports of $89.86 per bbl of oil. The table below sets forth NYMEX pricing as of October 14, 2011 for period ending June 30, 2014.

Assumed Market Prices for Oil ($/bbl)

Based on NYMEX Pricing

as of October 14, 2011

	2011	2012	2013	2014
January		$ 87.10	$ 88.58	$ 89.01
February		87.22	88.61	89.01
March		87.31	88.64	89.02

April		87.35	88.65	89.04
May		87.39	88.66	89.08
June		87.43	88.68	89.12
July	$ 93.40[1]	87.53	88.68	
August	98.14[1]	87.63	88.69	
September	84.12[1]	87.79	88.71	
October	86.89[1]	87.98	88.80	
November	86.80	88.24	88.91	
December	87.00	88.51	89.02	

(1) Based on settled NYMEX pricing.

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Natural Gas Liquids Prices. The assumed unhedged natural gas liquids prices utilized for purposes of preparing the target distributions are benchmarked at 49.2% of the oil prices set forth above under the heading Oil Prices on page 56 as well as a 1.9% to 3.0% negative differential from such prices in each relevant period. See Differentials on page 59.

Natural Gas Prices. The assumed natural gas prices utilized for purposes of preparing the target distributions are based on settled NYMEX pricing for July through October 2011, NYMEX forward pricing for the remainder of the period ending June 30, 2014 and assumed price increases after June 30, 2014 of 2.5% annually, capped at $7.00 per mmbtu. Using these assumptions, the price per mmbtu would reach the $7.00 cap in 2028. These prices are higher than the SEC-mandated pricing used in the reserve reports of $4.21 per mcf of natural gas. The table below sets forth NYMEX pricing as of October 14, 2011 for the period ending June 30, 2014.

Assumed Market Prices for Natural Gas ($/mmbtu)

Based on NYMEX Pricing

as of October 14, 2011

	2011	2012	2013	2014
January		$ 4.10	$ 4.79	$ 5.18
February		4.11	4.76	5.14
March		4.07	4.70	5.06
April		4.05	4.57	4.85
May		4.09	4.59	4.86
June		4.13	4.62	4.89
July	$ 4.36(1)	4.17	4.66	
August	4.37(1)	4.19	4.68	
September	3.86(1)	4.20	4.68	
October	3.76(1)	4.23	4.71	
November	3.70	4.38	4.83	
December	3.96	4.65	5.06	

(1) Based on settled NYMEX pricing.

Hedging. The trust will be a party to hedging arrangements pursuant to which the trust will hedge approximately 50% of the expected oil and natural gas liquids production and 37% of the trust s expected revenues upon which the target distributions from October 1, 2011 to September 30, 2015 are based. Except in connection with the restructuring of an existing hedge, after such date, no production will be hedged. See The Trust Hedging Arrangements beginning on page 47.

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The following tables illustrate the application of oil swaps between oil and natural gas liquids production, notional amount and weighted average fixed price for the hedging arrangements into which the trust will enter.

	Volume (mbbl)	Weighted Average Price (per bbl)
Oil:		
Q4 2011	89.7	$ 84.37
Q1 2012	89.2	84.99
Q2 2012	91.4	85.71
Q3 2012	97.2	86.40
Q4 2012	102.3	86.98
Q1 2013	99.4	87.37
Q2 2013	101.1	87.60
Q3 2013	104.1	87.79
Q4 2013	101.6	87.99
Q1 2014	97.7	88.08
Q2 2014	96.3	88.21
Q3 2014	97.1	88.34
Q4 2014	95.0	88.45
Q1 2015	92.5	88.59
Q2 2015	95.3	88.76
Q3 2015	80.6	88.90
Total Oil	1530.5	$ 87.42

	Volume (mbbl)	Weighted Average Price (per bbl)
Natural Gas Liquids:		
Q4 2011	150.1	$ 41.50
Q1 2012	151.4	41.80
Q2 2012	153.4	42.16
Q3 2012	161.5	42.50
Q4 2012	169.1	42.79
Q1 2013	168.3	42.98
Q2 2013	169.0	43.09
Q3 2013	170.5	43.18
Q4 2013	167.8	43.28
Q1 2014	167.1	43.33
Q2 2014	170.8	43.39
Q3 2014	166.0	43.46
Q4 2014	161.1	43.51
Q1 2015	159.7	43.58
Q2 2015	162.9	43.66
Q3 2015	148.5	43.73
Total Natural Gas Liquids	2597.2	$ 43.01

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

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

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

To prepare the target distributions, assumed differentials were subtracted from the NYMEX prices shown in the tables above, based on an analysis by Chesapeake of historical realized prices for production from the region.

The estimated realized prices for oil assume a $3.58 per barrel negative differential from the NYMEX futures price for oil to reflect recent field adjustments and post-production expenses. A flat dollar differential amount has been utilized because the realized oil differential has historically been stable for oil produced in the Colony Granite Wash.

The estimated realized prices for natural gas assume a negative differential which varies based on assumed NYMEX prices. For purposes of calculating the target distributions, the estimated differential is $1.23 per mcf in July 2011 and escalates to $1.95 per mcf in 2029, remaining flat thereafter.

The estimated realized prices for natural gas liquids are benchmarked at 49.2% of NYMEX settled and futures prices for oil based on an analysis by Chesapeake of the historical mix of hydrocarbon liquids that have been produced from its wells in the region. Additionally, the estimated prices assume a 1.9% to 3.0% negative differential from NYMEX settled and futures prices for oil associated with fees paid for gathering and processing of the natural gas liquids, consistent with Chesapeake s service contracts currently in place.

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

Administrative Expense. Trust administrative expenses per year are estimated to be approximately $1.0 million, although such costs could be greater or less depending on future events that cannot be predicted. Included in the annual estimate, among other miscellaneous items, 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. It has been assumed that the annual fee to Chesapeake will remain flat for the 20-year life of the trust, while the fees to the trustee and the Delaware trustee will escalate at a rate of approximately 2.5% annually starting in the first quarter of 2015. It has been assumed that the trust will also pay, out of the first cash payment received by the trust, the trustee s and Delaware trustee s legal expenses incurred in forming the trust as well as the trustee s acceptance fee in the amount of $10,000. These costs will be deducted by the trust before distributions are made to trust unitholders.

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

Tax Treatment of Royalty Interests. For U.S. federal income tax purposes, the Term PDP Royalty and the Term Development Royalty should be treated as debt instruments. Accordingly, the Term Royalties will be subject to the original issue discount, or OID, rules of the Internal Revenue Code, which require that payments

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made to the trust with respect to the Term Royalties will be treated first as consisting of a payment of interest to the extent of interest deemed accrued under the OID rules at the applicable federal rate and the excess, if any, will be treated as a payment of principal (which is non-taxable). For federal income tax purposes, the Perpetual PDP Royalties will be, and the Perpetual Development Royalties should be, treated as mineral royalty interests, which give rise to ordinary income subject to depletion.

Timing of Actual Cash Distributions. Quarterly cash distributions will be made approximately 60 days following the end of each calendar quarter to unitholders of record approximately 50 days following each calendar quarter. Due to the timing of Chesapeake s receipt of cash for production, it has been assumed that cash distributions for each quarter will include three months of production, including the first two months of the quarter just ended and the last month of the quarter prior to that one. The first distribution, which will cover the third quarter of 2011, is expected to be made on or about December 1, 2012 to record unitholders on or about November 21, 2011, and will generally include sales of oil, natural gas liquids and natural gas for the months of July and August 2011.

Applicable Taxes. Oklahoma imposes a tax on the production of oil and natural gas in the state at the statutory tax rate of approximately 7%. Current Oklahoma law provides for a reduced rate of approximately 1% for the first four years of production from horizontal wells so long as the well is producing before July 1, 2015. Prior to July 1, 2011, Oklahoma law provided for a reduced rate of approximately 1% for the first four years of production from horizontal wells; however, this reduced rate was limited to the earlier of (i) four years or (ii) when the well reached payout as defined under Oklahoma law. Thereafter, the Producing Wells would revert to the statutory tax rate or, if applicable, another reduced rate. Currently, some of the Producing Wells have reached payout and are subject to a tax rate in excess of 1%. Accordingly, the effective rate of production tax on the oil and gas attributable to the properties owned by the trust will be approximately 2% for the first four years of production. After the four year exemption period, the statutory rate of approximately 7% will apply to the properties.

Incentive Distributions. 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. The incentive distributions terminate upon completion of the subordination period.

Valuation of Perpetual Royalties. In estimating the cash available for distribution to trust unitholders following the Termination Date, we valued the royalty interests attributable to the Perpetual Royalties, which the trust will own on the Termination Date and subsequently sell, at $98.4 million as of the Termination Date. We determined this value using a discounted cash flow analysis as follows:

- a discount rate of 9%;

- estimated future production of 5.0 mmboe following the Termination Date, which is based on reserve and production data from the reserve reports attributable to the Perpetual Royalties; and

- assumed prices of $120.00 per bbl of oil as set forth above under the heading Oil Prices on page 56, $59.03 per bbl of natural gas liquids as set forth above under the heading Natural Gas Liquids Prices on page 57 and $7.00 per mmbtu of natural gas as set forth above under the heading Natural Gas Prices on page 57, each as adjusted as set forth above under the heading Differentials on page 59.

The actual value of the Perpetual Royalties sold by the trust following the Termination Date and the proceeds available for distribution to trust unitholders from such sale will depend on numerous factors out of Chesapeake s or the trust s control, including the estimated future production of the reserves attributable to the Perpetual Royalties on the Termination Date, current and expected commodity prices as of the Termination Date and the discount rate employed by prospective purchasers. For example, a discount rate of 6% would increase the estimated value noted above by $21.0 million. Conversely, a discount rate of 12% would decrease the estimated value noted above by $14.5 million.

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

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

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

- the assumption that a total of 34,312,500 common trust units and 11,437,500 subordinated units are issued and outstanding after the closing of the offering made hereby;
- an assumed initial public offering price of $20.00 per common unit (the midpoint of the price range set forth on the cover page of this prospectus);
- various realizations of oil, natural gas liquids and natural gas production levels estimated in the reserve reports;
- various assumed realized oil, natural gas liquids and natural gas prices;
- assumptions regarding applicable taxes and differentials; and
- other assumptions described above under Significant Assumptions Used to Calculate the Target Distributions beginning on page 56.

The tables give effect to the subordination and incentive distribution features that are contained in the terms of the trust. For a description of the way in which those features would impact trust unitholders distributions, please see Target Distributions and Subordination and Incentive Thresholds beginning on page 50. The assumed realized prices of oil, natural gas liquids and natural gas production shown have been chosen solely for illustrative purposes, and do not reflect any hedging assumptions.

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

The hedging arrangements for the trust will be in effect only through September 30, 2015, and thus there is likely to be greater fluctuation in cash distributions resulting from fluctuations in realized oil and natural gas liquids prices in periods subsequent to the

end of the term of the hedging arrangements. See Risk Factors beginning on page 20 for a discussion of various items that could impact production levels and the prices of oil, natural gas liquids and natural gas.

These distributions are sensitized to both assumed NYMEX oil and natural gas prices as well as the assumed production from the trust properties. The quarterly distributions in the tables below are based on assumptions outlined in Significant Assumptions Used to Calculate the Target Distributions beginning on page 56. The tables set forth below provide examples of possible distributions for the quarters ending September 30, 2011, December 31, 2011, March 31, 2012 and June 30, 2012 based on various NYMEX pricing and production assumptions.

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

The distributions below reflect average NYMEX futures prices as reported on October 14, 2011. The estimated oil and natural gas production used to calculate the distributions below is based on the reserve reports, and the sensitivity analysis assumes there will be no variation by location and that oil, natural gas liquids and natural gas production will continue to represent the same relative percentage of total production as estimated in the reserve reports.

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(1) Includes proceeds attributable to two months of production in July and August of 2011.

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THE UNDERLYING PROPERTIES

The Underlying Properties consist of the working interests owned by Chesapeake in the Colony Granite Wash in Washita County in western Oklahoma arising under leases and farmout agreements related to properties from which the PDP Royalty Interest and the Development Royalty Interest will be conveyed. The AMI consists of approximately 45,400 gross acres (28,700 net acres). There are more than 200 potential drilling locations within the AMI based on assumed spacing of four wells per 640-acre section. As of June 30, 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 44.3 mmboe (47.0% oil and natural gas liquids by volume). This amount includes 18.6 mmboe attributable to the PDP Royalty Interest and 25.7 mmboe attributable to the Development Royalty Interest, respectively. Certain of the Producing Wells commenced production in 2007. Chesapeake is currently the operator of 94% of the wells subject to the PDP Royalty Interest. Chesapeake owns an average 52.8% net revenue interest in the wells subject to the PDP Royalty Interest. The reserves attributable to the trust s royalty interests include the reserves that are expected to be produced from the Colony Granite Wash during the 20-year period in which the trust owns the royalty interests as well as the residual interest in the reserves that the trust will sell on or shortly following the Termination Date.

Overview of the Colony Granite Wash

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 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. The Colony Granite Wash is primarily a natural gas and natural gas condensate reservoir based on reserve volumes. However, oil and natural gas liquids production generates more revenue than natural gas production in the Colony Granite Wash due to prices that have historically been, and currently are, significantly higher for oil and natural gas liquids than for natural gas. Development costs for horizontal wells drilled and completed in the AMI average approximately $8.31 per boe, which is comparable to the development costs for other large-scale resource developments in the Mid-Continent in which Chesapeake operates.

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 initially be subject to the trust s royalty interests), and is also the most active driller, based on rig count, and the largest producer in the play. Since 2007, there have been 172 Des Moines horizontal wells drilled in the Colony Granite Wash. Of those 172 wells, Chesapeake has drilled 132 wells and participated in another 35 wells. As of June 30, 2011, there were 15 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.

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Historical Results from the Producing Wells

Natural gas and natural gas liquids produced from the Colony Granite Wash, including the Underlying Properties, are gathered by gathering pipelines owned by Chesapeake Midstream Partners under a contract that expires in approximately 18 years. Natural gas liquids and natural gas are processed at facilities owned by Enogex under a contract that expires in 2017 and then sold to a number of primary purchasers in the area. Oil produced from the Underlying Properties is gathered by gathering pipelines and equipment owned by Chesapeake Midstream Development or transported by trucks owned by third parties and sold to Plains. In the event of a loss of its contracts with Enogex or Plains, Chesapeake believes that the availability of other customers and service providers in the area is sufficient to accommodate such loss. Chesapeake also believes that the capacity of interstate pipelines is sufficient to accommodate the increased production of oil, natural gas liquids and natural gas from the Underlying Properties as currently contemplated.

The following table provides revenues and direct operating expenses relating to the Producing Wells for the years ended December 31, 2008, 2009 and 2010 and the six months ended June 30, 2010 and 2011, derived from the Underlying Properties statements of revenues and direct operating expenses included elsewhere in this prospectus.

	Year Ended December 31,			Six Months Ended June 30,	
	2008	2009	2010	2010	2011
				(unaudited)	
Oil, natural gas liquids and natural gas revenues[a]	$ 159,798	$ 123,594	$ 168,347	$ 87,533	$ 80,374
Direct operating expenses:					
Production expenses excluding ad valorem taxes	2,867	3,195	5,542	2,385	3,479
Ad valorem taxes	13	14	27	27	
Production taxes	4,604	2,521	3,271	1,903	1,929
Total direct operating expenses	7,484	5,730	8,840	4,315	5,408
Revenues in excess of direct operating expenses	$ 152,314	$ 117,864	$ 159,507	$ 83,218	$ 74,966

(a) Oil, natural gas liquids and natural gas revenues are net of post-production expenses, including gathering, storage, compression, transportation, processing, treating, dehydrating and non-affiliate marketing expenses.

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Oil, Natural Gas Liquids and Natural Gas Sales Prices and Production Expenses

The following table sets forth the production, average sales prices and production and post-production expenses (including any applicable taxes) for the Producing Wells on a historical basis for the years ended December 31, 2008, 2009 and 2010 and the six months ended June 30, 2011, and for the royalty interests on a pro forma basis for the years ended December 31, 2008, 2009 and 2010 and the six months ended June 30, 2011.

	Historical Results for Producing Wells				Pro Forma for Royalty Interests[a]			
	Year Ended December 31,			Six Months Ended June 30,	Year Ended December 31,			Six Months Ended June 30,
	2008	2009	2010	2011	2008	2009	2010	2011
Production:								
Oil (mbbls)	636	923	870	384	572	831	783	346
Natural gas liquids (mboe)	900	1,266	1,494	642	810	1,139	1,345	578
Natural gas (mmcf)	8,931	13,192	14,713	6,145	8,038	11,873	13,242	5,531
Total production (mboe)	3,024	4,387	4,816	2,050	2,722	3,948	4,335	1,845
Average sales prices:[b]								
Oil (per bbl)	$ 98.29	$ 60.18	$ 76.06	$ 93.48	$ 98.29	$ 60.18	$ 76.06	$ 93.48
Natural gas liquids (per boe)	$ 45.57	$ 26.64	$ 36.28	$ 42.67	$ 45.47	$ 26.64	$ 36.28	$ 42.67
Natural gas (per mcf)	$ 6.30	$ 2.60	$ 3.26	$ 2.78	$ 6.30	$ 2.60	$ 3.26	$ 2.78
Production expenses (per boe)[c]	$ 0.95	$ 0.73	$ 1.16	$ 1.70	$	$	$	$
Production taxes (per boe)[d]	$ 1.52	$ 0.57	$ 0.68	$ 0.94	$ 1.52	$ 0.57	$ 0.68	$ 0.94

(a) Pro forma figures are calculated as if the conveyances were in effect for the period indicated.

(b) Average sales prices are net of post-production expenses, including gathering, storage, compression, transportation, processing, treating, dehydrating and non-affiliate marketing expenses.

(c) Production expenses include lease operating costs and ad valorem taxes.

(d) Production taxes are generally based upon (i) volume produced and (ii) prices received for production.

Discussion and Analysis of Historical Results from the Producing Wells

Oil, Natural Gas Liquids and Natural Gas Revenues. During the year ended December 31, 2010, oil, natural gas liquids and natural gas revenues were $168.3 million compared to $123.6 million and $159.8 million for the years ended 2009 and 2008, respectively. The $44.7 million increase in revenue from 2009 to 2010 was primarily due to an increase in the average sales price for oil, natural gas liquids and natural gas from $28.17 to $34.95 per boe and a production increase of 429 mboe. The $36.2 million decrease in revenue from 2008 to 2009 was primarily due to a decrease in the average sales price for oil, natural gas liquids and natural gas from $52.83 to $28.17 per boe, offset by a production increase of 1,363 mboe.

During the six months ended June 30, 2011, oil, natural gas liquids and natural gas revenues were $80.4 million compared to $87.5 million for the six months ended June 30, 2010. The $7.1 million decrease in revenue was primarily due to a decrease in production of 379 mboe offset by an increase in the average sales price for oil, natural gas liquids and natural gas from $36.03 to $39.21 per boe.

Production Expenses. During the year ended December 31, 2010, production expenses, excluding ad valorem taxes, were $5.6 million compared to $3.2 million and $2.9 million for the years ended 2009 and 2008, respectively. The year over year increase was primarily due to an increase in the number of producing wells. On a unit-of-production basis, production expenses were $1.16 per boe in 2010 compared to $0.73 and $0.95 per boe in 2009 and 2008, respectively. The per unit increase from 2009 to 2010 was primarily the result of increased production expense rates as the U.S. economy emerged from the economic slowdown which occurred during the second half of 2008 and throughout 2009. The per unit decrease from 2008 to 2009 was primarily the result of decreased production expense rates due to the economic slowdown throughout 2009.

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During the six months ended June 30, 2011, production expenses, excluding ad valorem taxes, were $3.5 million in 2011 compared to $2.4 million for the six months ended June 30, 2010. The increase was primarily due to an increase in the number of producing wells. On a unit-of-production basis, production expenses were $1.70 per boe in the first half of 2011 compared to $0.99 per boe in the first half of 2010. The per unit increase was primarily the result of increased production expense rates in improving economic conditions.

Production Taxes. During the year ended December 31, 2010, production taxes were $3.3 million compared to $2.5 million and $4.6 million for the years ended 2009 and 2008, respectively. On a unit-of-production basis, production taxes were $0.68 per boe in 2010 compared to $0.57 and $1.52 per boe in 2009 and 2008, respectively. The $0.8 million increase in production taxes from 2009 to 2010 was primarily due to an increase in the average sales price for oil, natural gas liquids and natural gas from $28.17 to $34.95 per boe and a production increase of 429 mboe. The $2.1 million decrease in production taxes from 2008 to 2009 was primarily due to a significant decrease in the average sales price for oil, natural gas liquids and natural gas from $52.83 to $28.17 per boe.

Production taxes were $1.9 million for both the six months ended June 30, 2011 and the six months ended June 30, 2010, or $0.94 and $0.75 per boe, respectively.

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil, natural gas liquids and natural gas prices are higher.

Properties Related to the Development Royalty Interest

Chesapeake s average net revenue interest in the oil and natural gas properties underlying the Development Royalty Interest is approximately 52.0%. The Development Royalty Interest will entitle the trust to receive 50% of the proceeds attributable to Chesapeake s net revenue interest in future production of oil and natural gas resulting from the drilling of the Development Wells, with 25% of such proceeds attributable to the Term Development Royalty and 25% of such proceeds attributable to the Perpetual Development Royalty.

Chesapeake expects to operate approximately 93% of such wells until the completion of its drilling obligation. Until such time as Chesapeake has met its commitment to drill the Development Wells, 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 or lease acreage included within the AMI for its own account. During the life of the trust, 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 within 600 feet of any perforated interval of any Development or Producing Well.

Chesapeake may, in its sole discretion, make any acreage in the Development Area that was exchanged for other acreage in AMI subject to the Development Royalty Interest, so long as the aggregate exchanged acreage does not exceed five percent of the acreage currently subject to the Development Royalty Interest. In addition, if Chesapeake acquires any additional leases or interests in the AMI, such additional leases or interests may become subject to the Development Royalty Interest. See Description of the Royalty Interests Additional Features of the Royalty Interests beginning on page 79.

Oil, Natural Gas Liquids and Natural Gas Reserves

Ryder Scott estimated oil, natural gas liquids and natural gas reserves attributable to the Underlying Properties as of June 30, 2011. Numerous uncertainties are inherent in estimating reserve volumes and values, and the estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of the reserves may vary significantly from the original estimates.

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Proved Reserves of the Underlying Properties and Royalty Interests. The following table sets forth certain estimated proved reserves and the PV-10 value as of June 30, 2011 attributable to the Underlying Properties and the royalty interests, 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 by the royalty interest assigned to the trust in each property. The net revenues attributable to the trust s reserves are net of an assumed level of post-production costs and taxes based on historical results but have not been reduced by production and development costs, as the trust will not bear those costs. The reserves related to the Underlying Properties include all of Chesapeake s proved reserves expected to be economically produced from the Colony Granite Wash during the life of the properties. The reserves and revenues attributable to the trust s interests include only the reserves attributable to the Underlying Properties that are expected to be produced within the 20-year period in which the trust owns the royalty interests as well as the residual 50% interests in the reserves attributable to the Perpetual Royalties, which the trust will own on the Termination Date and subsequently sell. The reserve reports are included as Annex A to this prospectus.

	Proved Reserves(1)				
	Oil (mbbl)	Natural Gas Liquids (mbbl)	Natural Gas (mmcf)	Total (mboe)	PV-10 Value(2) (in thousands)
Underlying Properties:					
Developed	2,648	7,791	75,689	23,054	343,504
Undeveloped	8,290	18,640	179,931	56,919	510,087
Total	10,938	26,431	255,620	79,973	853,591
Royalty Interests:					
Developed (90%)	2,233	6,235	60,536	18,557	325,434
Undeveloped (50%)	4,002	8,319	80,325	25,709	485,706
Total	6,235	14,554	140,861	44,266	811,140

(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 liquids and natural gas for the period from July 1, 2010 through June 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 and, for the royalty interests, costs of marketing services provided by Chesapeake affiliates, which will not be charged to the trust. The reference prices and the equivalent weighted average wellhead prices are presented in the table below.

	Oil (per bbl)	Natural gas liquids (per bbl)	Natural gas (per mcf)
Trailing 12-month average (SEC) pricing	$ 89.86	$ 89.86	$ 4.21
Weighted average wellhead prices (Underlying Properties)	$ 86.08	$ 39.83	$ 2.93
Weighted average wellhread prices (royalty interests)	$ 86.09	$ 39.80	$ 2.86

(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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At the Termination Date, the estimated reserves attributable to the Perpetual Royalties, which the trust will own on the Termination Date and subsequently sell, are 5.0 mmboe. The PV-10 value of such reserves calculated using 12-month trailing SEC pricing as of June 30, 2011 is $9.2 million.

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

The Reserve Reports for the Underlying Properties and the Trust s Royalty Interests

All of the oil, natural gas liquids and natural gas reserves in this registration statement were estimated by Ryder Scott. The process to review and estimate the reserves began with the reservoir engineering department collecting and verifying all pertinent data, including but not limited to well test data, production data, historical pricing, cost information, property ownership interests, reservoir data, and geosciences data. This data was reviewed by various levels of Chesapeake management for accuracy before consultation with Ryder Scott. Ryder Scott was consulted with regularity during the reserve estimation process to review properties, assumptions, and any new data available. Internal reserve estimates and methodologies were compared to Ryder Scott s estimates and methodologies to test the reserve estimates and conclusions before the reserve estimates were included in this prospectus. Additionally, Chesapeake s senior management reviewed and approved the reserve reports contained herein.

Internal Controls. Chesapeake s Vice President of Reservoir Engineering is the technical person primarily responsible for overseeing the preparation of Chesapeake s and the trust s reserve estimates, is the primary contact with Ryder Scott and received the reserve reports from Ryder Scott. He has a Bachelor of Science degree in Petroleum Engineering with 35 years of practical industry experience, including 32 years of estimating and evaluating reserve information. In addition, the Vice President of Reservoir Engineering is a certified professional engineer in the state of Oklahoma and a member of the Society of Petroleum Engineers.

Chesapeake s Reservoir Engineering Department continually monitors asset performance and makes reserves estimate adjustments, as necessary, to ensure the most current reservoir information is reflected in reserves estimates. Reserve information includes production histories as well as other geologic, economic, ownership and engineering data. The department currently has a total of 97 full-time employees, comprised of 58 degreed engineers (10 serving in management capacities) and 37 engineering technicians with a minimum of a four-year degree in mathematics, economics, finance or other business or science field.

Chesapeake maintains a continuous education program for engineers and technicians on new technologies and industry advancements and also offers refresher training on basic skill sets.

In order to ensure the reliability of reserves estimates, internal controls observed within the reserve estimation process include:

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

Chesapeake follows comprehensive SEC-compliant internal policies to determine and report proved reserves. Reserves estimates are made by experienced reservoir engineers or under their direct supervision.

The Reservoir Engineering Department reviews all of Chesapeake s and the trust s reported proved reserves, including the reserves associated with the Underlying Properties and the trust, at the close of each quarter.

Each quarter, Reservoir Engineering Department managers, the Vice President of Reservoir Engineering, the Senior Vice President of Production and the Chief Operating Officer review all significant reserves changes and all new proved undeveloped reserves additions.

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Technologies. The reserve reports were prepared using decline curve analysis to determine the reserves of individual Producing Wells. After estimating the reserves of each proved developed well, it was determined that a reasonable level of certainty exists with respect to the reserves that can be expected from close offset undeveloped wells in the field. The continuity of the play across the AMI area was established by reviewing electric well logs, geologically mapping the analogous reservoir and reviewing extensive production data from 111 vertical and 164 horizontal wells. The proven undeveloped locations within the AMI are generally all offsets to the horizontal wells drilled and producing to date.

Ryder Scott. Ryder Scott, the independent petroleum engineering consultant, estimated all of the proved reserve information in this prospectus, in accordance with the definitions and regulations of the SEC and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities Oil and Gas. For the purposes of the reserve reports, Ryder Scott used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in the reserve reports have been estimated using deterministic methods. Ryder Scott used standard engineering and geosciences methods, or a combination of methods, such as performance analysis and analogy, that they considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. Ryder Scott s expertise is in petroleum engineering, geoscience, and petrophysical interpretation, not legal or accounting matters; they are not accountants, attorneys, or landmen. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, the conclusions from Ryder Scott necessarily represent only informed professional judgment. The titles to the properties have not been examined by Ryder Scott, nor has the actual degree or type of interest owned been independently confirmed. The data used in Ryder Scott s estimates were obtained from Chesapeake and the non-confidential files of Ryder Scott and were accepted as accurate. Supporting geoscience, field performance, and work data are on file in their office. The qualifications of the technical person at Ryder Scott primarily responsible for overseeing the estimate of the reserves include: 30 years of practical experience in the estimation and evaluation of petroleum reserves; a registered professional engineer in the state of Texas; and a Bachelor of Science degree in Electrical Engineering. These qualifications meet or exceed the Society of Petroleum Engineers standard requirements to be a professionally qualified Reserve Estimator and Auditor. Ryder Scott are independent petroleum engineers, geologists, geophysicists, and petrophysicists; Ryder Scott does not own an interest in these properties and are not employed on a contingent basis.

Well Locations

Chesapeake has over 200 potential drilling locations within the AMI, based on assumed spacing of four wells per 640-acre section, and may drill some of the Development Wells on units that encompass land controlled by third-party operators in order to maximize recovery in the field and also maximize the perforated length of each Development Well drilled. 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 52.0%. 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 52.0%, Chesapeake will receive proportionate credit. For instance, if Chesapeake drilled one well in which it has a 50% net revenue interest, and such well was completed with a perforated length of 3,000 feet, such well would count for purposes of the development agreement as only 0.82 Development Wells (i.e., 3,000/3,500 x 50%/52.0%). As a result, Chesapeake may be required to drill more or less than 118 Development Wells in order to complete its drilling obligation.

Additional Information Regarding the Underlying Properties

Drilling Activity. The following table sets forth information with respect to the wells Chesapeake drilled or participated in during the periods indicated. All wells drilled during the periods shown were development wells. The

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information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of reserves found. Productive wells consist of producing wells and wells capable of producing, including oil wells awaiting connection to production facilities and natural gas wells awaiting pipeline connections to commence deliveries. Gross wells are the total number of producing wells in which Chesapeake has a working interest and net wells are the sum of Chesapeake s fractional working interests owned in gross wells. Since July 1, 2011, Chesapeake has drilled and completed six Development Wells and has drilled two additional wells in the AMI that are awaiting completion as of the date of this prospectus. Assuming the successful completion of these two wells, such wells will count toward the satisfaction of Chesapeake s drilling obligation.

	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	16	11	14	8	19	11
Dry						
Total	16	11	14	8	19	11

Productive Wells. The following table sets forth the number of productive wells within the AMI in which Chesapeake owned working interests as of June 30, 2011 and from which Chesapeake will convey the royalty interests to the trust, all of which are classified as natural gas wells.

	Gross	Net
Productive Wells	69	45

Developed and Undeveloped Acreage. The following table sets forth information regarding developed and undeveloped acreage held by Chesapeake within the AMI as of September 30, 2011. Substantially all of the leases associated with the Underlying Properties are held by production and not subject to expiration so long as production continues in paying quantities.

	Developed Acreage(1)		Undeveloped Acreage(2)	
	Gross(3)	Net(4)	Gross(3)	Net(4)
Acreage held by Chesapeake within the AMI	41,555	26,445	3,807	2,215

(1) Gross and net developed acres are acres spaced or assignable to productive wells. The drilling unit for each Colony Granite Wash horizontal well comprises 640 acres. As such, developed acreage may include up to 640 acres assigned to each Colony Granite Wash horizontal well. Future drilling opportunities may exist within both our developed and undeveloped acreage through increased density wells and drilling of proved undeveloped and unproved locations in the same formation, as well as other non-producing formations.

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

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

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

Sale and Abandonment of the Underlying Properties

Chesapeake and any transferee will have the right to abandon its interest in any well or property comprising a portion of the Underlying Properties if Chesapeake determines in good faith and in accordance with the Reasonably Prudent Operator Standard that such well or property ceases to produce, or is not capable of producing, oil, natural gas liquids or natural gas in commercially paying quantities. Upon termination of the lease, that portion of the royalty interests relating to the abandoned property will be extinguished. See Description of the Royalty Interests Additional Features of the Royalty Interests Abandonment of Underlying Properties on page 81.

Following the satisfaction of its drilling obligation, Chesapeake generally may, without the consent or approval of the trust unitholders, sell all or a portion of its interests in the Underlying Properties. In any such sale by Chesapeake, the Underlying Properties must be sold subject to and burdened by the royalty interests, except that Chesapeake may require the trust to release the trust s royalty interests on such Underlying Properties with an aggregate value to the trust not to exceed $5.0 million during any 12-month period. In such event, the trust must receive an amount equal to the fair value to the trust of any royalty interests it sells. See Description of the Royalty Interests Additional Features of the Royalty Interests Sale and Release of Underlying Properties on page 81.

Marketing and Post-Production Services

Pursuant to the terms of the conveyances creating the royalty interests, Chesapeake will have the responsibility to market, or cause to be marketed, the oil, natural gas liquids and natural gas production related to the Underlying Properties. While marketing costs of non-affiliates of Chesapeake may be deducted from the proceeds upon which the royalty payments will be calculated, the terms of the conveyances creating the royalty interests do not permit Chesapeake or any of its affiliates to include their own marketing costs in any such deductions. As a result, the proceeds to the trust from the sales of oil, natural gas liquids and natural gas production from the Underlying Properties will be determined based on the same price (net of post-production expenses and severance taxes) that Chesapeake receives from third parties for oil, natural gas liquids and natural gas production attributable to Chesapeake s remaining interest in the Underlying Properties.

Chesapeake Energy Marketing, Inc. (CEMI), a wholly owned subsidiary of Chesapeake, markets the majority of Chesapeake s operated production. CEMI enters into oil, natural gas liquids and natural gas sales arrangements with large aggregators of supply and these arrangements may be on a month-to-month basis or may be for a term of up to one year or longer. The oil, natural gas liquids and natural gas are sold at market prices and subsequently any applicable post-production expenses will be deducted. CEMI sells production from the Underlying Properties to a diverse group of aggregators, the identity of which changes from time to time.

Post-production expenses will be deducted from proceeds paid to the trust. Chesapeake Midstream Partners and Chesapeake Midstream Development will provide post-production services, including gathering, treating and compression, while third parties, including Enogex and Plains, will provide processing, transportation and other post-production services. The proceeds paid to the trust will be reduced by Chesapeake s deductions for these post-production expenses. However, the trust will not be responsible for costs of marketing services provided by Chesapeake or any of its affiliates.

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

The cost of post-production services is included within the assumed differentials from NYMEX pricing discussed above under Target Distributions and Subordination and Incentive Thresholds beginning on page 50.

Post-production expenses may increase or decrease in the future. The post-production expenses attributable to third-party arrangements will be negotiated based on market conditions at the time or pursuant to a state or federal regulatory proceeding. Chesapeake will be permitted to deduct from the proceeds available to the trust other post-production expenses necessary to enhance the value of the oil, natural gas liquids and natural gas from the Underlying Properties and to transport such production to market.

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

Title to Properties

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

Chesapeake acquired its interests in the Underlying Properties through a variety of means, including through the acquisition of oil and natural gas leases by Chesapeake directly from the mineral owner, through assignments of oil and natural gas leases to Chesapeake by the lessee who originally obtained the leases from the mineral owner, through farmout agreements that grant Chesapeake the right to earn interests in the properties covered by such agreements by drilling wells, and through acquisitions of other oil and natural gas interests by Chesapeake.

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

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

rights reserved to or vested in the appropriate governmental agency or authority to control or regulate the Underlying Properties;

customarily acceptable title defects that (a) do not result in another person s superior claim of title to the relevant Underlying Properties or (b) are not such as to (in the aggregate) interfere materially with the operation, value or use of the Underlying Properties; and

other liens, charges, encumbrances, contracts, agreements, instruments, obligations, conditions, reservations, burdens, defects and irregularities affecting the Underlying Properties that (a) do not secure an obligation in respect of borrowed money and (b) are not such as to (in the aggregate) interfere materially with the operation, value or use of the Underlying Properties.

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

Chesapeake will record the conveyance of the royalty interests in the real property records of Washita County, Oklahoma and, if necessitated by an expansion of the AMI, in Custer County, Oklahoma. Chesapeake and the trust believe that the recordation of the conveyance of the royalty interests in the appropriate real property records in Oklahoma will constitute the conveyance of fully vested real property interests under Oklahoma law or interests in hydrocarbons in place or to be produced under Oklahoma law. Oklahoma law, however, is not entirely clear as to whether an overriding royalty interest is a real property interest. While the Oklahoma Supreme Court has recently held that royalty interests are real property interests, such cases did not expressly overturn prior Oklahoma Supreme Court cases holding that an overriding royalty interest was not necessarily a real property interest. In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that will convey the royalty interests to the trust, if a bankruptcy court held that (a) the royalty interests did not constitute fully vested real property interests or interests in hydrocarbons in place or to be produced or (b) the royalty interests were not otherwise eligible to be excluded from the bankruptcy estate under federal bankruptcy law, the royalty interests may be treated as unsecured claims of the trust against Chesapeake. If that were the case, creditors of Chesapeake would be able to claim the royalty interests as an asset of the bankruptcy estate to be sold to satisfy obligations to them and the trust could lose the entire value of the royalty interests to senior creditors of Chesapeake.

Chesapeake believes that its title to the Underlying Properties is, and the trust s title to the royalty interests will be, good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions as are not so material as to detract substantially from the use or value of such properties or royalty interests. Prior to the drilling of a Development Well, Chesapeake expects to obtain a drilling title opinion to identify defects in title to the leasehold. Chesapeake s in-house legal department frequently issues drilling title opinions for the company s leasehold, which title opinions are written to the Oklahoma Title Examination Standards published by the Real Property Law Section of the Oklahoma Bar Association. Frequently, as a result of such examinations, certain curative work must be done to correct identified title defects, and such curative work entails time and expense. Chesapeake will not be relieved of its obligation to drill a well if such title examination prior to drilling reveals a title defect preventing Chesapeake from drilling in such drill site. Chesapeake will also be obligated to provide the trust with a true-up for any breach of Chesapeake s warranty of title in the conveyance to the trust of the royalty interests that is discovered after the conveyance to the trust. See Description of the Royalty Interests Additional Features of the Royalty Interests True-up on page 80.

Competition and Markets

The oil and natural gas industry is highly competitive. Chesapeake competes with both major integrated and other independent oil, natural gas liquids and natural gas companies in acquiring desirable leasehold acreage, producing properties and the equipment and expertise necessary to explore, develop and operate its properties and market its production. Some of Chesapeake s competitors may have larger financial and other resources than Chesapeake. The oil, natural gas liquids and natural gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquified natural gas. Competitive conditions may be affected by future legislation and regulations as the U.S. develops new energy and climate-related policies. In addition, some of Chesapeake s larger competitors may have a competitive advantage when responding to factors that affect demand for oil, natural gas liquids and natural gas production, such as changing prices, domestic and foreign political conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of pipelines and other transportation facilities, and overall economic conditions. Chesapeake believes that its technological expertise, its exploration, land, drilling and production capabilities and the experience of its management generally enable it to compete effectively.

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

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Regulation

General. All of Chesapeake s operations are conducted onshore in the United States. The U.S. natural gas and oil industry is regulated at the federal, state and local levels, and some of the laws, rules and regulations that govern its operations carry substantial penalties for noncompliance. These regulatory burdens increase Chesapeake s cost of doing business and, consequently, affect its profitability.

Regulation of Natural Gas and Oil Operations. Chesapeake s exploration and production operations are subject to various types of regulation at the U.S. federal, state and local levels. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation include, but are not limited to:

- the location of wells;
- the method of drilling and completing wells;
- the surface use and restoration of properties upon which wells are drilled;
- water withdrawal;
- the plugging and abandoning of wells;
- the disposal of fluids used or other wastes generated in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Chesapeake s operations are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units (regarding the density of wells that may be drilled in a particular area) and the unitization or pooling of natural gas and oil properties. In this regard, some states, such as Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas and New Mexico, rely on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units and therefore, more difficult to fully develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of oil, natural gas liquids and natural gas Chesapeake can produce and to limit the number of wells and the locations at which it can drill.

Chesapeake operates a number of natural gas gathering systems. The U.S. Department of Transportation and certain state agencies regulate the safety and operating aspects of the transportation and storage activities of these facilities. There is currently no price regulation of the company s sales of oil, natural gas liquids and natural gas, although governmental agencies may elect in the future to regulate certain sales.

Chesapeake does not anticipate that compliance with existing laws and regulations governing exploration, production and natural gas gathering will have a material adverse effect upon its capital expenditures, earnings or competitive position.

Environmental, Health and Safety Regulation. The business operations of Chesapeake and its ownership and operation of oil, natural gas liquids and natural gas interests are subject to various federal, state and local environmental, health and safety laws and regulations pertaining to the release, emission or discharge of materials into the environment, the generation, storage, transportation, handling and disposal of materials (including solid and hazardous wastes), the safety of employees, or otherwise relating to pollution, preservation, remediation or protection of human health and safety, natural resources, wildlife or the environment. Chesapeake must take into account the cost of complying with environmental regulations in planning, designing, constructing, drilling, operating and abandoning wells and related surface facilities. In most instances, the regulatory frameworks relate to the handling of drilling and production materials, the disposal of drilling and

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production wastes, and the protection of water and air. In addition, Chesapeake s operations may require it to obtain permits for, among other things,

- air emissions;

- the construction and operation of underground injection wells to dispose of produced saltwater and other non-hazardous oilfield wastes; and

- the construction and operation of surface pits to contain drilling muds and other non-hazardous fluids associated with drilling operations.

Delays in obtaining permits, an inability to obtain new permits or revocation of Chesapeake s current permits due to noncompliance could result in the imposition of fines and could inhibit Chesapeake s ability to drill the Development Wells or continue production from the Producing Wells.

Federal, state and local laws may require Chesapeake to remove or remediate previously disposed wastes, including wastes disposed of or released by Chesapeake or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations at contaminated areas, or to perform remedial well plugging operations or response actions to reduce the risk of future contamination. Federal laws, including the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and analogous state laws impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and persons that disposed of or arranged for the disposal of hazardous substances at the site. CERCLA and analogous state laws also authorize the EPA, state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such actions.

Other federal and state laws, in particular the federal Resource Conservation and Recovery Act, or RCRA, regulate hazardous and non-hazardous solid wastes. In the course of its operations, Chesapeake generates petroleum hydrocarbon wastes and ordinary industrial wastes. Under a longstanding legal framework, certain of these wastes are not subject to federal regulations governing hazardous wastes, though they may be regulated under other federal and state laws. Chesapeake believes it is in substantial compliance with all regulations regarding the handling and disposal of oil and gas exploration and production wastes from its operations, including with respect to the Underlying Properties. These wastes may in the future be designated as hazardous wastes and may thus become subject to more rigorous and costly compliance and disposal requirements. Such additional regulation could have a material adverse effect on the cash distributions to the trust unitholders.

Federal and state occupational safety and health laws require Chesapeake to organize and maintain information about hazardous materials used, released or produced in its operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. Chesapeake is also subject to the requirements and reporting set forth in federal workplace standards.

Chesapeake has made and will continue to make expenditures to comply with environmental, health and safety regulations and requirements. These are necessary business costs in the oil and natural gas industry. Although Chesapeake is not fully insured against all environmental, health and safety risks, and Chesapeake s insurance does not cover any penalties or fines that may be issued by a governmental authority, it maintains insurance coverage which it believes is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental, health and safety laws and regulations, as well as claims for damages to property or persons, resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Chesapeake. Chesapeake believes that it is in material compliance with existing environmental, health and safety regulations. It believes that the cost of maintaining compliance with these existing regulations will not have a material adverse effect on its business, financial position and results of operation, but new or more stringent regulations could increase the cost of doing business and could have a material adverse effect on the proceeds available to the trust. Moreover, accidental

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releases or spills may occur in the course of Chesapeake s operations on the Underlying Properties causing Chesapeake to incur significant costs and liabilities, including for third-party claims for damage to property and natural resources or personal injury.

Hydraulic Fracturing. Vast quantities of oil, natural gas liquids and natural gas deposits exist in deep shale and other formations. It is customary in Chesapeake s industry to recover oil, natural gas liquids and natural gas from these deep shale formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing is 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. These formations are generally geologically separated and isolated from fresh ground water supplies by protective rock layers. Chesapeake s well construction practices include installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into aquifers.

Legislative, regulatory, guidance and enforcement efforts at the federal level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Hydraulic fracturing is typically regulated by state oil and gas commissions. However, 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. Industry groups have filed suit challenging the EPA s assertion of authority as improper rule making. 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. The results of EPA s guidance, including its definition of diesel fuel, the related litigation, EPA s study, and other analyses by federal and state agencies to assess the impacts of hydraulic fracturing could each spur further action toward federal legislation and regulation of hydraulic fracturing activities. Also, for the second consecutive session, legislation has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. While some states have adopted regulations that could restrict hydraulic fracturing in certain circumstances, Oklahoma s regulations recently received positive approval from the State Review of Oil & Natural Gas Environmental Regulations and, as such, the agency has not undertaken further rulemaking. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the Oklahoma state level, such legal requirements could make it more difficult or costly for Chesapeake to perform fracturing to stimulate production in the Underlying Properties and thereby affect the determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, Chesapeake s fracturing activities, including with respect to its operations at the Underlying Properties, could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil, natural gas liquids and natural gas 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 our 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 such as Chesapeake s. 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 the oil, natural gas liquids and natural gas that it sells. The potential increase in Chesapeake s operating costs could include new or increased costs to obtain permits, operate and maintain its equipment and facilities, install new emission controls on its equipment and facilities, acquire allowances to authorize its greenhouse gas emissions, pay taxes related to its 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 liquids and natural gas.

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DESCRIPTION OF THE ROYALTY INTERESTS

The royalty interests will be conveyed to the trust by Chesapeake by means of conveyance instruments that will be recorded in the appropriate real property records in Washita County, Oklahoma.

The royalty interests will be conveyed from Chesapeake s interest in the Underlying Properties effective as of July 1, 2011. 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 liquids and natural gas attributable to Chesapeake s net revenue interest in the Producing 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 production of oil, natural gas liquids and natural gas attributable to Chesapeake s net revenue interest in the Development Wells.

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 52.8% net revenue interest in the Producing Wells. Therefore, the trust will have an average 47.5% net revenue interest in the Producing Wells. Chesapeake on average owns a 52.0% 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 26.0% net revenue interest in the Development Wells. Chesapeake s actual net revenue interest in any particular Producing Well or Development Well (or the average net revenue interest as a whole) may differ from these averages.

PDP Royalty Interest

The PDP Royalty Interest entitles the trust to receive an amount of cash for each calendar quarter equal to 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 liquids and natural gas production attributable to Chesapeake s net revenue interest in the Producing Wells. Proceeds from the sale of oil, natural gas liquids and natural gas production attributable to Chesapeake s net revenue interest in the Producing Wells in any calendar quarter means, for any calendar quarter commencing on or after July 1, 2011, the amount calculated based on actual production volumes attributable to Chesapeake s net revenue interest in the Producing Wells, in each case after deducting the trust s proportionate share of:

- any taxes levied on the severance or production of the oil, natural gas liquids and natural gas produced from the Producing Wells and any property taxes attributable to the oil, natural gas liquids and natural gas produced from the Producing Wells; and
- post-production expenses, which will generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas liquids and natural gas produced, as applicable (excluding costs for marketing services provided by Chesapeake).

Proceeds payable to the trust from the sale of oil, natural gas liquids and natural gas production attributable to the Producing Wells in any calendar quarter will not be subject to any deductions for any expenses attributable to exploration, drilling, development, operating, maintenance or any other costs incident to the production of oil, natural gas liquids and natural gas attributable to the Producing Wells, including any costs to drill, complete or plug and abandon a Producing Well. Additionally, costs associated with water production, handling, treatment and disposal, the installation of artificial lift equipment and any further completion activities, such as re-fracturing a well, will be borne by the operator of the well.

Development Royalty Interest

The Development Royalty Interest entitles the trust to receive an amount of cash for each calendar quarter equal to 50% of the proceeds (exclusive of any production or development costs but after deducting post-

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production expenses and any applicable taxes) from the sale of estimated oil, natural gas liquids and natural gas production attributable to Chesapeake s net revenue interest in the Development Wells. Proceeds from the sale of oil, natural gas liquids and natural gas production attributable to Chesapeake s net revenue interest in the Development Wells in any calendar quarter means, for any calendar quarter commencing on or after July 1, 2011, the amount calculated based on actual production volumes attributable to Chesapeake s net revenue interest in the Development Wells, in each case after deducting the trust s proportionate share of:

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

- post-production expenses, which will generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas liquids and natural gas produced, as applicable (excluding costs for marketing services provided by Chesapeake).

Proceeds payable to the trust from the sale of oil, natural gas liquids and natural gas production attributable to the Development Wells in any calendar quarter will not be subject to any deductions for any expenses attributable to exploration, drilling, development, operating, maintenance or any other costs incident to the production of oil, natural gas liquids and natural gas attributable to the Development Wells, including any costs to drill, complete or plug and abandon a Development Well. Additionally, costs associated with water production, handling, treatment and disposal, the installation of artificial lift equipment and any further completion activities, such as re-fracturing a well, will be borne by the operator of the well.

Sale of the Perpetual Royalties

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

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

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

Additional Features of the Royalty Interests

Reasonably Prudent Operator Standard. In performing certain of its obligations under the conveyance instruments, including marketing production, contracting for post-production services and operating the Producing Wells and 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

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commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard and to cause such operators to only drill Development Wells on locations classified as proven undeveloped at the time of drilling.

True-up. In the conveyances for the PDP Royalty Interest, Chesapeake warrants to the trust that the trust will receive a specified amount of net revenue interest in respect of a Producing Well. In the conveyances for the Development Royalty Interest, Chesapeake warrants to the trust that the trust will receive a net revenue interest in respect of a Development Well that will not be less than the net revenue interest used to calculate Chesapeake s satisfaction of its drilling obligation for such well. Chesapeake s actual net revenue interest in a well may be greater or less than the net revenue interest warranted to the trust in the conveyances for various reasons, including mistakes in the record title documents or mistakes in identifying mineral interest owners when leasing properties.

If Chesapeake determines that its actual net revenue interest with respect to a Producing Well or Development Well is less than the net revenue interest warranted to the trust in the conveyances relating to such well, the trust will continue to receive payments based on the net revenue interest warranted in the conveyances and Chesapeake s retained interest in such well will be reduced to the extent required to allow the trust to receive a royalty interest based on the net revenue interest warranted in the conveyances. If Chesapeake were to have an insufficient retained interest in a well out of which to make the foregoing true-up, then Chesapeake would be required to pay to the trust with respect to such well an amount equal to the difference between the payments the trust actually receives from the royalty interests in such well and the payments the trust would have received from such well had Chesapeake s actual net revenue interest been the amount warranted in the conveyances. Any true-up payment must be paid from proceeds attributable to production from the Underlying Properties.

By way of example, if Chesapeake s net revenue interest warranted in the conveyances as to a Development Well were 50%, the trust would receive a net revenue interest of 25% in such well. If Chesapeake later determined that its actual net revenue interest as to such well was only 40%, resulting in the trust s holding only a 20% net revenue interest in the well, Chesapeake would reduce its retained interest in the well by 5% to provide the trust with the net revenue interest in the well warranted in the conveyances (i.e., 20% actual net revenue interest + 5% true-up by Chesapeake = 25% net revenue interest).

If Chesapeake determines that its actual net revenue interest with respect to a well is greater than the net revenue interest warranted to the trust in the conveyances as to such well, the trust will continue to receive royalty payments based on the net revenue interest warranted in the conveyances and Chesapeake will not receive any additional credit for such well in respect of its drilling obligation.

If Chesapeake sells any of its revenue interests in the Underlying Properties, the buyer will assume the true-up obligations with respect to the properties purchased by it.

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

amounts withheld or placed in escrow by a purchaser are not considered to be received by the owner of the underlying property until actually collected;

amounts received by the owner of the underlying property and promptly deposited with a nonaffiliated escrow agent will not be considered to have been received until disbursed to it by the escrow agent; and

amounts received by the owner of the underlying property and not deposited with an escrow agent will be considered to have been received.

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

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

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

Exchange and Addition of Acreage. Chesapeake may at its option at any time prior to the completion of its drilling obligation cause the trust to exchange leased acreage subject to the royalty interests, free and clear of such royalty interests, for other leased acreage within the Development Area, and cause such leased acreage exchanged to the trust to be made subject to the royalty interests as set forth in the conveyances. Following such an exchange, the exchange acreage in the Development Area will be included in the AMI for all purposes of the development agreement, and the corresponding acreage in the AMI exchanged therewith will be excluded from the AMI for all purposes of the development agreement. In addition, in the event Chesapeake acquires any additional leases or interests in the AMI (other than renewals or extensions) prior to the completion of its drilling obligation, Chesapeake may at its option make such additional leases or interests subject to the royalty interests with respect to any Development Wells subsequently drilled on such acreage. In no event, however, may any exchange of acreage or any addition of leased acreage or interests be effected unless Chesapeake certifies to the trust that, among other things, all of the aggregate acreage attributable to the exchanged leases or additional leases or interests does not exceed five percent of the acreage initially subject to the royalty interests and that, with respect to exchange acreage, the reasonable quantity of proved undeveloped reserves of such exchange acreage does not differ significantly from the reasonable quantity of proved undeveloped reserves being exchanged for such acreage, and, with respect to additional leases or interests, the reserve profile of such acreage is consistent with the reserve profile of the acreage that would be developed in the absence of such additional acreage.

Abandonment of Underlying Properties. Chesapeake and any transferee will have the right to abandon its interest in any well or property comprising a portion of the Underlying Properties if Chesapeake determines in good faith and in accordance with the Reasonable Prudent Operator Standard that such well or property ceases to produce, or is not capable of producing, oil, natural gas liquids or natural gas in commercially paying quantities. 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. Upon termination of the lease, that portion of the royalty interests relating to the abandoned property will be extinguished.

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Maintenance of Books and Records. Chesapeake must maintain books and records sufficient to determine the amounts payable for the royalty interests to the trust. Quarterly and annually, Chesapeake must deliver to the trustee a statement of the computation of the proceeds for each computation period as well as quarterly drilling and production results. See Where You Can Find More Information beginning on page 119.

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

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DESCRIPTION OF THE TRUST AGREEMENT

Creation and Organization of the Trust; Amendments

The trust was created under Delaware law as a separate legal entity to acquire and hold the royalty interests for the benefit of the trust unitholders pursuant to an agreement among Chesapeake, the trustee and the Delaware trustee. The royalty interests are passive in nature and neither the trust nor the trustee has any control over, or responsibility for, costs relating to the operation of the Underlying Properties. Neither Chesapeake nor other operators of the Underlying Properties have any contractual commitments to the trust to provide additional funding or to conduct further drilling on or to maintain their ownership interest in any of these properties other than the obligations of Chesapeake to drill the Development Wells. After the conveyance of the royalty interests, however, Chesapeake will retain an interest in each of the Underlying Properties. For a description of the Underlying Properties and other information relating to them, see The Underlying Properties beginning on page 64.

The trust agreement will provide that the trust s business activities will generally be limited to owning the royalty interests, being a party to the hedging arrangements and activities reasonably related thereto, including activities required or permitted by the terms of the conveyances related to the royalty interests. As a result, the trust will not be permitted to acquire other oil, natural gas liquids and natural gas properties or royalty interests except as otherwise discussed under Description of the Royalty Interests Additional Features of the Royalty Interests beginning on page 79. Additionally, following the completion of this offering, the trust will not be able to issue any additional trust units.

The beneficial interests in the trust are divided into 45,750,000 trust units. Each trust unit represents an equal undivided beneficial interest in the property of the trust. Please read Description of the Trust Units beginning on page 89 for additional information concerning the trust units.

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

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

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

- dispositions of the trust s assets;
- indemnification of the trustee;
- reimbursement of out-of-pocket expenses of Chesapeake when acting as the trust s agent;
- termination of the trust; and
- amendments of the trust agreement.

Certain amendments to the trust agreement do not require the vote of the trust unitholders. See Permitted Amendments on page 86.

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The business and affairs of the trust will be managed by the trustee. The trustee will have no ability to manage or influence the operations of the Underlying Properties. Chesapeake currently operates 94% of the Producing Wells and expects to operate approximately 93% of the Development Wells until the completion of its drilling obligation, but will have no ability to manage or influence the operations of the trust, except through its limited voting rights as a holder of trust units.

Assets of the Trust

Upon completion of this offering, the principal assets of the trust will consist of the PDP Royalty Interest and the Development Royalty Interest, the development agreement, the Drilling Support Lien, the administrative services agreement, the hedging arrangements and any cash and temporary investments being held for the payment of expenses and liabilities and for distribution to the trust unitholders. See The Trust beginning on page 44 for more information.

Duties and Powers of the Trustee; Liability of the Trustee

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

The trustee s principal duties consist of:

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

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

The trustee may create a cash reserve to pay for future expenses of the trust. If the trustee determines that the cash on hand and the cash to be received are insufficient to cover the trust s expenses, the trustee may cause the trust to borrow funds required to pay the expenses. The trust may borrow the funds from any person, including the trustee or its affiliates or, as described below, Chesapeake. The terms of such indebtedness, if funds were loaned by the entity serving as trustee or Delaware trustee, must be similar to the terms which such entity would grant to a similarly situated, unaffiliated commercial customer, and such entity shall be entitled to enforce its rights with respect to any such indebtedness as if it were not then serving as trustee or Delaware trustee. If the trust borrows funds, the trust unitholders will not receive distributions until the borrowed funds are repaid (except in certain circumstances, where the trust borrows funds from Chesapeake). For information regarding Chesapeake s obligation to loan funds to the trust in certain limited circumstances, see Chesapeake Obligation to Fund Trust Expenses in Certain Circumstances on page 87.

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

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

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

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

The trust may not acquire any asset except the royalty interests, the other assets described above under Assets of the Trust on page 84, interests acquired in connection with foreclosure under the Drilling Support Lien and cash and temporary cash investments, and it may not engage in any investment activity except investing cash on hand. Chesapeake, acting as hedging manager for the trust, may cause the trust to restructure existing hedges in certain circumstances.

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

- prosecute or defend, and settle, claims of or against the trust or its agents;
- foreclose on the Drilling Support Lien if Chesapeake does not satisfy its drilling obligation on or before June 30, 2016, and contract with a third-party operator to drill any remaining Development Wells, and transfer a portion of the trust s assets in connection therewith;
- retain professionals and other third parties to provide services to the trust;

- charge for its services as trustee;
- retain funds to pay for future expenses and deposit them with one or more banks or financial institutions (which may include the trustee to the extent permitted by law);
- lend funds at commercial rates to the trust to pay the trust s expenses; and
- seek reimbursement from the trust for its out-of-pocket expenses.

In discharging its duty to trust unitholders, the trustee may act in its discretion and will be liable to the trust unitholders only for willful misconduct, bad faith or gross negligence, and certain taxes, fees and other charges based on fees, commissions or compensation received by the trustee in connection with the transactions contemplated by the trust agreement. The trustee will not be liable for any act or omission of its agents or employees unless the trustee acted with willful misconduct, bad faith or gross negligence in its selection and retention. The trustee will be indemnified individually or as the trustee for any liability or cost that it incurs in the administration of the trust, except in cases of willful misconduct, bad faith or gross negligence. The trustee will have a lien on the assets of the trust as security for this indemnification and its compensation earned as trustee. Trust unitholders will not be liable to the trustee for any indemnification. See Description of the Trust Units Liability of Trust Unitholders on page 90. The trustee is obligated to ensure that all contractual liabilities of the trust are limited to the assets of the trust.

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Merger or Consolidation of Trust

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

Trustee s Power to Sell Trust Assets

The trustee may sell trust assets, including the royalty interests, under any of the following circumstances:

- the sale is requested by Chesapeake, following the satisfaction of its drilling obligation, in accordance with the provisions of the trust agreement (see Description of the Royalty Interests Additional Features of the Royalty Interests Sale and Release of Underlying Properties on page 81);
- the sale is approved by the vote of holders representing a majority of the trust units and a majority of the common units (excluding common units owned by Chesapeake and its affiliates) in each case voting in person or by proxy at a meeting of such holders at which a quorum is present; except that at any time that Chesapeake and its affiliates collectively own less than 10% of the outstanding trust units, the standard for approval will be the vote of 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; or
- in connection with a foreclosure on the Drilling Support Lien.

Upon dissolution of the trust the trustee must sell the remaining royalty interests. No trust unitholder approval is required in this event. See Duration of the Trust; Sale of Royalty Interests on page 87.

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

Permitted Amendments

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

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

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Liabilities of the Trust; Fees and Expenses

The trust will be a party to oil and natural gas liquids hedging arrangements and could have payment obligations under such arrangements. Otherwise, the trust does not conduct an active business and the trustee has little power to incur obligations. As a result, it is expected that the trust will only incur liabilities for routine administrative expenses, such as legal, accounting, tax advisory, engineering, printing and other administrative and out-of-pocket fees and expenses incurred by or at the direction of the trustee or the Delaware trustee, including tax return and Schedule K-1 preparation and mailing costs; independent auditor fees; and registrar and transfer agent fees. The trust will also be responsible for paying costs associated with annual and quarterly reports to unitholders. Moreover, the trustee s and the Delaware trustee s compensation, and the fee payable to Chesapeake pursuant to the administrative services agreement, will be paid out of the trust s assets. See The Trust beginning on page 44, for more information on these costs.

Chesapeake Obligation to Fund Trust Expenses in Certain Circumstances

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

Duration of the Trust; Sale of Royalty Interests

The trust will not dissolve until the Termination Date, which is June 30, 2031, unless:

- the trust sells all of the royalty interests;
- cash available for distribution is less than $1.0 million for any four consecutive quarters;
- the holders of a majority of the trust units and a majority of the common units (excluding common units owned by Chesapeake and its affiliates) in each case voting in person or by proxy at a meeting of such holders at which a quorum is present vote in favor of dissolution; except that at any time that Chesapeake and its affiliates collectively own less than 10% of the outstanding trust units, the standard for approval will be 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; or
- the trust is judicially dissolved.

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

Dispute Resolution

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

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Tax Matters

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

Miscellaneous

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

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

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

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DESCRIPTION OF THE TRUST UNITS

Each trust unit is a unit of the beneficial interest in the trust and is entitled to receive cash distributions from the trust on a pro rata basis. Each trust unitholder has the same rights regarding each of his trust units as every other trust unitholder has regarding his units. The trust will have 45,750,000 trust units outstanding upon completion of the offering, consisting of 34,312,500 common units and 11,437,500 subordinated units.

Common Units; Subordinated Units

The common units and subordinated units will have identical rights and privileges, except with respect to their voting rights and rights to receive distributions. For a discussion of unitholders voting rights, see Voting Rights of Trust Unitholders beginning on page 90.

The subordinated units will be entitled to receive pro rata distributions from the trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is no less than the applicable quarterly subordination threshold. If there is insufficient 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. For more information, see Target Distributions and Subordination and Incentive Thresholds beginning on page 50.

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

Distributions; Income Computations

Cash distributions to trust unitholders will be made by the trust from its available funds for each calendar quarter. Royalty interest payments due to the trust with respect to any calendar quarter will be based on actual production volumes attributable to the trust properties for the first two months of the quarter just ended as well as the last month of the immediately preceding quarter (as measured at Chesapeake metering systems) and actual revenues received for such volumes. Chesapeake will make the royalty interest payments to the trust within 35 days of the end of each calendar quarter. In addition, any payment due from or required to be made to the counterparties under the trust s hedging arrangements will be paid by the 40th day following the end of such calendar quarter. Taking into account the receipt and disbursement of all such amounts, the trustee will determine for such calendar quarter the amount of funds available for distribution to the trust unitholders. Available funds are the excess cash, if any, received by the trust over the trust s expenses for that quarter. Available funds will be reduced by any cash the trustee decides to hold as a reserve against future liabilities.

The amount of available funds for distribution each quarter will be payable to the trust unitholders of record approximately 50 days following the end of such calendar quarter or such later date as the trustee determines is required to comply with legal or stock exchange requirements. The trustee will distribute cash approximately 60 days (or the next succeeding business day following such day if such day is not a business day) following such calendar quarter to each person who was a trust unitholder of record on the quarterly record date, together with interest expected to be earned on the amount of such quarterly distribution from the date of receipt thereof by the trustee to the payment date.

Unless otherwise advised by counsel or the IRS, the trustee will treat the income and expenses of the trust for each quarter as belonging to the trust unitholders of record on the quarterly record date that occurs in such quarter. Trust unitholders will recognize income and expenses for tax purposes in the quarter the trust receives or pays those amounts, rather than in the quarter the trust distributes them. Minor variances may occur. For example, the trustee could establish a reserve in one quarter that would not result in a tax deduction until a later quarter. The trustee could also make a payment in one quarter that would be amortized for tax purposes over several months. See U.S. Federal Income Tax Considerations beginning on page 95.

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Transfer of Trust Units

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

Tax Schedules and Periodic Reports

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

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

Liability of Trust Unitholders

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

Voting Rights of Trust Unitholders

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

Unless otherwise required by the trust agreement, a matter may be approved or disapproved by the vote of a majority of the trust units held by the trust unitholders voting in person or by proxy at a meeting where there is a quorum. This is true, even if a majority of the total outstanding trust units did not approve it.

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

- dissolve the trust (except in accordance with its terms);

- amend the trust agreement, the royalty conveyances, the administrative services agreement, the development agreement or the Drilling Support Lien (except with respect to certain matters that do not adversely affect the right of trust unitholders in any material respect);

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- merge or consolidate or convert the trust with or into another entity; or

- approve the sale of all or any material part of the assets of the trust.

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

At any time when Chesapeake and its affiliates own less than 10% of the outstanding trust units, the vote of the holders of a majority of 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 will be required to take the actions described above.

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

Comparison of Trust Units and Common Stock

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

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

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

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TRUST UNITS ELIGIBLE FOR FUTURE SALE

General

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

Upon completion of this offering, there will be 45,750,000 trust units outstanding and Chesapeake will own 11,437,500 common units and 11,437,500 subordinated units (assuming no exercise by the underwriters of their option to purchase additional common units). All of the subordinated units will convert into common units at the end of the fourth full calendar quarter following satisfaction of Chesapeake s drilling obligation. The sale of these units could have an adverse impact on the price of our common units or on any trading market that may develop.

All of the 22,875,000 common units sold in this offering, or the 26,306,250 common units if the underwriters exercise their option to purchase additional common units in full, will be freely tradable without restriction under the Securities Act. The 11,437,500 common trust units to be held by Chesapeake (8,006,250 common trust units if the underwriters exercise their option to purchase additional common units in full) following completion of the offering will be restricted securities within the meaning of Rule 144 under the Securities Act and may not be sold other than through registration under the Securities Act or pursuant to an exemption from registration, subject to the restrictions on transfer contained in the lock-up agreements described below and in Underwriting beginning on page 113.

Chesapeake Lock-up Agreement

In connection with this offering, Chesapeake has agreed, for a period of 180 days after the date of this prospectus, that neither it nor its subsidiaries will offer, sell, contract to sell or otherwise dispose of or transfer any trust units or any securities convertible into or exchangeable for trust units, without the prior written consent of Morgan Stanley & Co. LLC and Raymond James & Associates, Inc. See Underwriting beginning on page 113 for a description of this lock-up agreement. Upon the expiration of this lock-up agreement, all of the units held by Chesapeake will be eligible for sale in the public market under Rule 144 of the Securities Act, subject to volume limitations and other restrictions contained in Rule 144, or through registration under the Securities Act.

Rule 144

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

- 1.0% of the total number of the securities outstanding, or

- the average weekly reported trading volume of the common units for the four calendar weeks prior to the sale.

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

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Registration Rights Agreement

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

- subject to the lock-up restrictions described above and under Underwriting, beginning on page 113, to use its reasonable best efforts to file a registration statement, including, if so requested, a shelf registration statement, with the SEC as promptly as practicable following receipt of a notice requesting the filing of a registration statement from holders representing a majority of the then outstanding registrable trust units;

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

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

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

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

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

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

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

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U.S. FEDERAL INCOME TAX CONSIDERATIONS

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

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

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

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

For the reasons described below, Bracewell & Giuliani LLP has not rendered an opinion with respect to the following specific U.S. federal income tax issues: (a) the treatment of a trust unitholder whose trust units are loaned to a short seller to cover a short sale of trust units (please read Tax Consequences of Trust Unit Ownership Treatment of Short Sales on page 104); (b) whether the trust s convention for allocating taxable income and losses is permitted by existing Treasury Regulations (please read Disposition of Trust Units Allocations Between Transferors and Transferees on page 107); and (c) whether percentage depletion will be available to a trust unitholder or the extent of the percentage depletion deduction available to any trust unitholder (please read Tax Consequences of Trust Unit Ownership Tax Treatment of the Perpetual Royalties beginning on page 102).

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

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

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

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

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

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

Classification of the Trust as a Partnership

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

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

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

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

In rendering its opinion, Bracewell & Giuliani LLP has relied on factual representations made by the trust and Chesapeake. The representations made by the trust and Chesapeake upon which Bracewell & Giuliani LLP has relied are:

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

(b) The trust is, and will be organized and operated in accordance with (i) the trust agreement and (ii) the description thereof in this prospectus;

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

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

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

If the trust fails to meet the Qualifying Income Exception, other than a failure that is determined by the IRS to be inadvertent and that is cured within a reasonable time after discovery (in which case the IRS may also require the trust to make adjustments with respect to the trust s unitholders allocable share of trust income, gain, loss or deduction or pay other amounts), the trust will be treated as if it had transferred all of its assets, subject to liabilities, to a newly formed corporation, on the first day of the year in which the trust fails to meet the Qualifying Income Exception, in return for stock in that corporation, and then distributed that stock to the unitholders in liquidation of their interests in the trust. This deemed contribution and liquidation should be tax-free to the trust unitholders and the trust so long as the trust s liabilities do not exceed the tax basis of the trust s assets. Thereafter, the trust would be treated as an association taxable as a corporation for federal income tax purposes.

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

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

Partner Status

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

A beneficial owner of trust units whose trust units have been transferred to a short seller to complete a short sale would appear, as a result, to lose his status as a partner with respect to those trust units for U.S. federal income tax purposes. Please read Tax Consequences of Trust Unit Ownership Treatment of Short Sales on page 104. Income, gain, deductions or losses would not appear to be reportable by a trust unitholder who is not a partner for federal income tax purposes, and any cash distributions received by a trust unitholder who is not a partner for federal income tax purposes would therefore appear to be fully taxable as ordinary income. These unitholders are urged to consult their own tax advisors with respect to their tax considerations related to holding trust units. The references to unitholders in the discussion that follows are to persons who are treated as partners in the trust for federal income tax purposes.

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

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

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

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

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

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

Consistent with the foregoing, Chesapeake and the trust intend to treat the Perpetual Royalties as mineral royalty interests for U.S. federal income tax purposes. In addition, Chesapeake and the trust intend to treat the Term Royalties as debt instruments for U.S. federal income tax purposes subject to the Treasury Regulations applicable to contingent payment debt instruments (the CPDI regulations), and the trust will agree to be bound by Chesapeake s application of the CPDI regulations, including Chesapeake s determination of the rate at which interest will be deemed to accrue on such interests. No assurance can be given that the IRS will not assert that

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such interests should be treated differently. Such different treatment could affect the amount, timing and character of income, gain or loss in respect of an investment in trust units and could require a trust unitholder to accrue interest income at a rate different than the comparable yield described below. Please read Tax Consequences of Trust Unit Ownership Tax Treatment of the Term Royalties beginning on page 100, and Tax Consequences of Trust Unit Ownership Tax Treatment of the Perpetual Royalties beginning on page 102.

Tax Consequences of Trust Unit Ownership

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

Accounting Method and Taxable Year. The trust will use the year ending December 31 as its taxable year and the accrual method of accounting for U.S. federal income tax purposes. Each trust unitholder will be required to include in income his share of the trust s income, gain, loss, deduction and credit for the trust s taxable year ending within or with his taxable year. In addition, a trust unitholder who has a taxable year ending on a date other than December 31 and who disposes of all of his trust units following the close of the trust s taxable year but before the close of his taxable year must include his share of the trust s income, gain, loss, deduction and credit in his taxable income for his taxable year, with the result that he will be required to include in income for his taxable year his share of more than 12 months of the trust s income, gain, loss, deduction and credit. Please read Disposition of Trust Units Allocations Between Transferors and Transferees on page 107.

A trust unitholder s initial tax basis for his trust units will be the amount he paid for the trust units. That basis will be increased by his share of the trust s income and gain and decreased, but not below zero, by distributions from the trust, by the trust unitholder s share of the trust s losses, if any, by depletion deductions taken by him to the extent such deductions do not exceed his proportionate allocated share of the adjusted tax basis of the Perpetual Royalties, and by his share of the trust s expenditures that are not deductible in computing taxable income and are not required to be capitalized. Please read Disposition of Trust Units Recognition of Gain or Loss beginning on page 106.

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

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

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

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

Bracewell & Giuliani LLP is of the opinion that, with the exception of the issues described in Disposition of Trust Units Allocations Between Transferors and Transferees on page 107, allocations under the trust agreement will be given effect for U.S. federal income tax purposes in determining a unitholder s share of an item of income, gain, loss, deduction or credit.

Treatment of Trust Distributions. Distributions by the trust to a trust unitholder generally will not be taxable to the trust unitholder for U.S. federal income tax purposes, except to the extent the amount of any such cash distribution exceeds his tax basis in his trust units immediately before the distribution. The trust s cash distributions in excess of a unitholder s tax basis (if any) generally will be considered to be gain from the sale or exchange of the trust units, taxable in accordance with the rules described under Disposition of Trust Units beginning on page 106.

Ratio of Taxable Income to Distributions. The trust estimates that a purchaser of trust units in this offering who owns those trust units from the date of closing of this offering through the record date for distributions for the period ending December 31, 2014, will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be approximately 55% of the cash distributed with respect to that period. These estimates and assumptions are subject to, among other things, numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond the trust s control. Further, the estimates are based on current tax law and tax reporting positions that the trust will adopt and with which the IRS could disagree. Accordingly, the trust cannot assure unitholders that these estimates will prove to be correct. The actual percentage of distributions that will correspond to taxable income could be higher or lower than expected, and any differences could be material and could materially affect the value of the trust units.

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

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

the product of (i) the adjusted issue price (as defined below) of the debt instrument as of the beginning of the accrual period; and (ii) the comparable yield to maturity (as defined below) of such debt instrument, adjusted for the length of the accrual period;

divided by the number of days in the accrual period; and

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

The issue price of the debt instrument represented by each production payment held by the trust is the portion of the first price at which a substantial amount of the trust units is sold to the public, excluding sales to

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

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

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

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

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

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

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

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

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by the trust. If either of the Term Royalties is not treated as a production payment (and not otherwise as a debt instrument) for U.S. federal income tax purposes, the trust intends to take the position that its basis in the Term Royalty is recouped in proportion to the production from the Term Royalty.

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

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

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

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

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

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

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deductions based on cost depletion cannot exceed the trust unitholder s share of the total adjusted tax basis in the property.

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

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

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

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

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

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

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

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

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

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

- any of the trust s income, gain, loss, deduction or credit with respect to those trust units would not be reportable by the trust unitholder;
- any cash distributions received by the trust unitholder as to those trust units would be fully taxable; and
- all of these distributions would appear to be ordinary income.

Bracewell & Giuliani LLP has not rendered an opinion regarding the tax treatment of a trust unitholder whose trust units are loaned to a short seller to cover a short sale of trust units; therefore, trust unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing and loaning their trust units. The IRS has previously announced that it is studying issues relating to the tax treatment of short sales of partnership interests. Please also read Disposition of Trust Units Recognition of Gain or Loss beginning on page 106.

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

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

The recently enacted Health Care and Education Reconciliation Act of 2010 will impose a 3.8% Medicare tax on certain investment income earned by individuals, estates and trusts for taxable years beginning after December 31, 2012. For these purposes, investment income generally includes a trust unitholder s allocable share of the trust s income and gain realized by a trust unitholder from a sale of trust units. In the case of an individual, the tax will be imposed on the lesser of (i) the trust unitholder s net income from all investments, and (ii) the amount by which the trust unitholder s adjusted gross income exceeds $250,000 (if the trust unitholder is married and filing jointly or a surviving spouse), $125,000 (if the trust unitholder is married and filing separately) or $200,000 (in any other case). In the case of an estate or trust, the tax will be imposed on the lesser of (a) the undistributed net investment income of the estate or trust, or (b) the excess of the adjusted gross income of the estate or trust over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

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

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

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

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

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

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

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Disposition of Trust Units

Recognition of Gain or Loss. Gain or loss will be recognized on a sale of trust units equal to the difference between the amount realized and the trust unitholder s tax basis for the trust units sold. A trust unitholder s amount realized will be measured by the sum of the cash or the fair market value of other property received. The amount realized should be reduced by the unused net negative adjustments attributable to the trust units disposed of as described above under Tax Consequences of Trust Unit Ownership Tax Treatment of the Term Royalties beginning on page 100. A trust unitholder s adjusted tax basis in his trust units will be equal to the trust unitholder s original purchase price for the trust units, increased by income and decreased by losses or deductions previously allocated to the trust unitholder and by distributions to the trust unitholder and depletion deductions claimed by the trust unitholder.

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

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

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

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

a short sale;

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- an offsetting notional principal contract; or
- a futures or forward contract with respect to the partnership interest or substantially identical property.

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

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

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

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

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

Tax-Exempt Organizations and Certain Other Investors

Ownership of trust units by employee benefit plans, other tax-exempt organizations, non-resident aliens, non-U.S. corporations and other non-U.S. persons raises issues unique to those investors and, as described below,

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may have substantially adverse tax consequences to them. If a potential investor is a tax-exempt entity or a non-U.S. person, then it should consult a tax advisor before investing in the trust units.

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

Non-U.S. Persons. The trust (or the appropriate intermediary if units are held in Street Name) will be required to withhold (at a 30% rate or lower applicable treaty rate) on gross interest and royalty income paid to non-U.S. trust unitholders. The trustee is authorized to adopt such conventions related to withholding as it deems appropriate for the proper administration of the trust. Any convention adopted by the trustee may not be consistent with the Internal Revenue Code or the Treasury Regulations. Neither the trust nor Bracewell & Giuliani LLP can assure trust unitholders that the IRS will not successfully challenge any withholding convention adopted by the trustee.

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

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

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

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

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

Administrative Matters

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

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

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

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

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

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

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

(b) whether the beneficial owner is:

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

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

(iii) a tax-exempt entity;

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

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

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

Accuracy-Related Penalties. An additional tax equal to 20% of the amount of any portion of an underpayment of tax that is attributable to one or more specified causes, including negligence or disregard of rules or regulations, substantial understatements of income tax and substantial valuation misstatements, is imposed by the Internal Revenue Code. No penalty will be imposed, however, for any portion of an underpayment if it is shown that there was a reasonable cause for that portion and that the taxpayer acted in good faith regarding that portion.

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

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

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

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

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

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

Reportable Transactions. If the trust were to engage in a reportable transaction, the trust (and possibly the unitholders) would be required to make a detailed disclosure of the transaction to the IRS. A transaction may be a reportable transaction based upon any of several factors, including the fact that it is a type of tax avoidance transaction publicly identified by the IRS as a listed transaction or that it produces certain kinds of losses for partnerships, individuals, S corporations, and trusts in excess of $2 million in any single year, or $4 million in any combination of 6 successive tax years. The trust s participation in a reportable transaction could increase the likelihood that the trust s U.S. federal income tax information return (and possibly the unitholders tax return) would be audited by the IRS. Please read Trust Information Returns and Audit Procedures beginning on page 108.

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

- accuracy-related penalties with a broader scope, significantly narrower exceptions, and potentially greater amounts than described above at Accuracy-Related Penalties beginning on page 109;

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

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

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

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STATE TAX CONSIDERATIONS

The following is intended as a brief summary of certain information regarding state income taxes and other state tax matters affecting individuals who are trust unitholders. Bracewell & Giuliani LLP has not rendered an opinion on the state tax consequences of an investment in the trust. Trust unitholders are urged to consult their own legal and tax advisors with respect to these matters.

Prospective investors should consider state and local income tax consequences of an investment in the trust units. The trust will own royalty interests burdening specified oil and natural gas properties located in Washita County, Oklahoma. If the trust is treated as a partnership for federal income tax purposes, it should also be treated as a partnership for Oklahoma income tax purposes. Trust unitholders generally will be subject to Oklahoma income tax on trust royalty income allocable to the unitholders; accordingly, trust unitholders generally will be required to file Oklahoma state income tax returns and pay taxes in Oklahoma, and may be subject to penalties for failure to comply with such requirements. The current highest marginal rates for the payment of Oklahoma state income taxes are 5.5% for individuals, trusts and estates, and 6% for corporations. Generally, Oklahoma taxpayers are entitled to a depletion allowance on oil and natural gas income for state income tax purposes equal to the greater of cost depletion or percentage depletion, with the percentage depletion allowance for most taxpayers being 22%, but not in excess of 50% of the net income from the property (without regard to depletion); however, each trust unitholder should consult their own legal and tax advisors to determine the Oklahoma depletion allowance specifically applicable to such unitholder. Although payments to out-of-state interest owners, including beneficial owners such as trust unitholders, in respect of Oklahoma oil and natural gas income generally are subject to withholding for Oklahoma income tax purposes at the rate of 5%, an exception exists for publicly traded partnerships that furnish detailed information concerning beneficial owners to the Oklahoma Tax Commission. The trust plans to furnish such information and comply with those Oklahoma Tax Commission requirements as necessary to avoid withholding for Oklahoma state income tax purposes. Special withholding rules may apply to non-U.S. trust unitholders. Although Oklahoma municipalities are statutorily authorized to assess income taxes, no municipality has enacted such a tax. If an Oklahoma municipality were to enact an income tax, the tax could not be levied on nonresidents of the municipality.

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ERISA CONSIDERATIONS

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

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

- whether the investment satisfies the prudence requirements of Section 404(a)(1)(B) of ERISA;
- whether the investment satisfies the diversification requirements of Section 404(a)(1)(C) of ERISA; and
- whether the investment is in accordance with the documents and instruments governing the plan as required by Section 404(a)(1)(D) of ERISA.

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

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

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UNDERWRITING

Under the terms and subject to the conditions contained in an underwriting agreement dated the date of this prospectus, the underwriters named below, for whom Morgan Stanley & Co. LLC and Raymond James & Associates, Inc. are acting as representatives, have severally agreed to purchase the number of common units indicated below:

Underwriter	Number of Common Units
Morgan Stanley & Co. LLC	
Raymond James & Associates, Inc.	
Deutsche Bank Securities Inc.	
Goldman, Sachs & Co.	
Wells Fargo Securities, LLC	
Barclays Capital Inc.	
BNP Paribas Securities Corp.	
Citigroup Global Markets Inc.	
Credit Agricole Securities (USA) Inc.	
Credit Suisse Securities (USA) LLC	
Mitsubishi UFJ Securities (USA), Inc.	
Mizuho Securities USA Inc.	
Natixis Securities Americas LLC	
RBS Securities Inc.	
Scotia Capital (USA) Inc.	
UBS Securities LLC	
Comerica Securities, Inc.	
Banco Bilbao Vizcaya Argentaria, S.A.	
DnB NOR Markets, Inc.	
Macquarie Capital (USA) Inc.	
Nomura Securities International, Inc.	
PNC Capital Markets LLC	
SMBC Nikko Capital Markets Limited	
SunTrust Robinson Humphrey, Inc.	
TD Securities (USA) LLC	
Total	22,875,000

The underwriting agreement provides that the obligations of the underwriters to pay for and accept delivery of the common units offered by this prospectus are subject to the satisfaction of customary conditions, including the approval of certain legal matters by their counsel; the accuracy of representations and warranties made by the trust and Chesapeake to the underwriters; there having been no material adverse change in financial markets or in the condition (financial or otherwise), business, prospects, management or results of operations of the trust, the underlying properties or Chesapeake; and other similar conditions. The underwriters are obligated to take and pay for all of the common units offered by this prospectus, if any are taken. However, the underwriters are not required to take or pay for the common units covered by the underwriters option to purchase additional common units described below.

The underwriters initially propose to offer part of the common units directly to the public at the public offering price listed on the cover page of this prospectus and part to certain dealers at a price that represents a concession not in excess of $ per common unit under the public offering price. After the initial offering of the common units, the offering price and other selling terms may from time to time be varied by the representatives.

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The trust has granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to an aggregate of 3,431,250 additional common units at the public offering price listed on the cover page of this prospectus, less underwriting discounts and commissions. To the extent the option is exercised, each underwriter will become obligated, subject to certain conditions, to purchase approximately the same percentage of the additional common units as the number listed next to the underwriter s name in the preceding table bears to the total number of common units listed next to the names of all underwriters in the preceding table.

If the underwriters do not exercise their option to purchase additional common units, the trust will deliver 3,431,250 common units to a subsidiary of Chesapeake upon the option s expiration. If and to the extent the underwriters exercise their option to purchase additional common units, the number of common units purchased by the underwriters pursuant to such exercise will be sold to the public and the remainder, if any, will be delivered to a subsidiary of Chesapeake. Accordingly, the exercise of the underwriters option to purchase additional common units will not affect the total number of common units outstanding.

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

The common units have been approved for listing on the New York Stock Exchange under the symbol CHKR. In connection with the listing of the trust units on the New York Stock Exchange, the underwriters will undertake to sell round lots of 100 units or more to a minimum of 400 beneficial owners.

Chesapeake has agreed that, subject to specified exceptions, without the prior written consent of Morgan Stanley & Co. LLC and Raymond James & Associates, Inc. on behalf of the underwriters, Chesapeake and its subsidiaries will not, during the period ending 180 days after the date of this prospectus:

- offer, sell, contract to sell, announce the intention to sell or pledge any of the common units;
- grant or sell any option or contract to purchase any of the common units;
- enter into any swap or other agreement that transfers any of the economic consequences of ownership of or otherwise transfer or dispose of, directly or indirectly, any of the common units; or
- dispose of or hedge any of the common units or securities convertible into or exchangeable for common units.

The 180-day restricted period described in the preceding paragraph will be automatically extended if:

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

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

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In order to facilitate the offering of the common units, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the common units. In connection with the offering, the underwriters may purchase and sell common units in the open market. These transactions may include short sales, stabilizing transactions and purchases to cover positions created by short sales. Short sales involve the sale by the underwriters of a greater number of common units than they are required to purchase in the offering, and a short position represents the amount of such sales that have not been covered by subsequent purchases. A covered short position is a short position that is not greater than the amount of additional common units for which the underwriters option described above may be exercised. The underwriters can close out a covered short sale by exercising their option to purchase additional common units or purchasing units in the open market. In determining the source of units to close out a covered short sale, the underwriters will consider, among other things, the open market price of units compared to the price available under their option to purchase additional common units. The underwriters may also sell units in excess of their option to purchase additional common units, creating a naked short position. The underwriters must close out any naked short position by purchasing units in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common units in the open market after pricing that could adversely affect investors who purchase in this offering. As an additional means of facilitating this offering, the underwriters may bid for, and purchase, common units in the open market to stabilize the price of the common units. Finally, the underwriting syndicate may reclaim selling concessions allowed to an underwriter or a dealer for distributing the common units in the offering, if the syndicate repurchases previously distributed common units in transactions to cover syndicate short positions, in stabilization transactions or otherwise. These activities may raise or maintain the market price of the common units above independent market levels or prevent or retard a decline in the market price of the common units. The underwriters are not required to engage in these activities and may end any of these activities at any time.

The following table shows the amount per unit and total underwriting discounts and commissions the trust will pay to the underwriters (dollars in thousands, except per unit). The amounts are shown assuming both no exercise and full exercise of the underwriters option to purchase additional common units.

Paid by the Trust	No Exercise	Full Exercise
Per Common Unit	$	$
Total	$	$

In addition, the trust will pay Morgan Stanley & Co. LLC and Raymond James & Associates, Inc. an aggregate structuring fee of $ (or $ if the underwriters exercise their option to purchase additional common units in full) for evaluation, analysis and structuring of the trust.

Chesapeake estimates that the expenses payable by Chesapeake and the trust, excluding underwriting discounts and commissions, in connection with this offering will be approximately $2.6 million. The underwriters have agreed to reimburse Chesapeake for up to $150,000 in expenses incurred by it in connection with this offering.

Chesapeake, the trust and the underwriters have agreed to indemnify each other against certain liabilities, including liabilities under the Securities Act of 1933.

Prior to this offering, there has been no public market for trust units. The initial public offering price was determined by negotiations between Chesapeake and the representatives. Among the factors considered in determining the initial public offering price were estimates of distributions to trust unitholders, overall quality of the oil, natural gas liquids and natural gas to be produced from the Underlying Properties, industry and market conditions, the information set forth in this prospectus or otherwise available to the representatives and the general conditions of the securities market at the time of this offering.

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The estimated initial public offering price range set forth on the cover page of this prospectus is subject to change as a result of market conditions and other factors. The trust and the underwriters cannot assure you that the prices at which the common units will sell in the public market after this offering will not be lower than the initial public offering price or that an active trading market in the trust s common units will develop and continue after this offering.

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

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. Certain of the underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various financial advisory, investment banking, commercial banking and other services for Chesapeake and its affiliates, for which they received or will receive customary fees and expenses. Affiliates of Morgan Stanley & Co. LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co., Wells Fargo Securities, LLC, Barclays Capital Inc., BNP Paribas Securities Corp., Citigroup Global Markets Inc., Credit Agricole Securities (USA) Inc., Credit Suisse Securities (USA) LLC, Mitsubishi UFJ Securities (USA), Inc., Mizuho Securities USA Inc., Natixis Securities Americas LLC, RBS Securities Inc., Scotia Capital (USA) Inc., UBS Securities LLC, Comerica Securities, Inc., Banco Bilbao Vizcaya Argentaria, S.A., DnB NOR Markets, Inc., Macquarie Capital (USA) Inc., Nomura Securities International, Inc., PNC Capital Markets LLC, SMBC Nikko Capital Markets Limited, SunTrust Robinson Humphrey, Inc. and TD Securities (USA) LLC are lenders under Chesapeake s revolving credit facility and, in that respect, will receive a substantial portion of the net proceeds from this offering through the repayment of borrowings outstanding under such credit facility.

In addition, affiliates of Morgan Stanley & Co. LLC, Barclays Capital Inc., Citigroup Global Markets Inc., Credit Agricole Securities (USA) Inc., RBS Securities Inc., Scotia Capital (USA) Inc., UBS Securities LLC, Comerica Securities, Inc., Banco Bilbao Vizcaya Argentaria, DnB NOR Markets, Inc., Nomura Securities International, Inc., S.A., SMBC Nikko Capital Markets Limited, SunTrust Robinson Humphrey, Inc., and TD Securities (USA) LLC are lenders under the revolving bank credit facility of Chesapeake Midstream Development. Affiliates of Morgan Stanley & Co. LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co., Wells Fargo Securities, LLC, Barclays Capital Inc., Citigroup Global Markets Inc., Credit Agricole Securities (USA) Inc., Credit Suisse Securities (USA) LLC, RBS Securities Inc., Scotia Capital (USA) Inc., UBS Securities LLC, Comerica Securities, Inc., Banco Bilbao Vizcaya Argentaria, S.A., SMBC Nikko Capital Markets Limited and TD Securities (USA) LLC are lenders under the revolving bank credit facility of Chesapeake Midstream Partners, L.P. Affiliates of Morgan Stanley & Co. LLC, Deutsche Bank Securities Inc., Goldman, Sachs & Co., Wells Fargo Securities, LLC, Barclays Capital Inc., BNP Paribas Securities Corp., Credit Agricole Securities (USA) Inc., Credit Suisse Securities (USA) LLC, Natixis Securities Americas LLC, Scotia Capital (USA) Inc., Macquarie Capital (USA) Inc., Nomura Securities International, Inc. and TD Securities (USA) LLC are counterparties to Chesapeake s multi-counterparty secured hedging facility, and an affiliate of Wells Fargo Securities, LLC acts as collateral agent under such facility. Deutsche Bank Securities Inc., Citigroup Global Markets Inc. and RBS Securities Inc. acted as Deal Managers for Chesapeake s tender offer for various tranches of its contingent convertible senior notes in April 2011. Affiliates of certain of the underwriters are parties to volumetric production payment transactions with Chesapeake and will be counterparties to hedging contracts with the trust.

Furthermore, certain of the underwriters and their respective affiliates may, from time to time, enter into arms-length transactions with the trust in the ordinary course of their business for which they may receive customary fees and reimbursement of expenses. In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their

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own account and for the accounts of their customers, and such investment and securities activities may involve securities or instruments of the trust or Chesapeake or their affiliates. The underwriters and their respective affiliates may also make investment recommendations or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long or short positions in such securities and instruments.

A prospectus in electronic format may be made available on websites maintained by one or more underwriters, or selling group members, if any, participating in this offering. The representatives may agree to allocate a number of common units to underwriters for sale to their online brokerage account holders. Internet distributions will be allocated by the representatives to the underwriters that may make Internet distributions on the same basis as other allocations.

At the request of Chesapeake, the underwriters have reserved for sale, at the initial public offering price, up to 5% of the common units offered hereby for Chesapeake s directors, officers, and certain other persons associated with Chesapeake. The sales will be made by Morgan Stanley & Co. LLC through a directed unit program. It is not certain if these persons will choose to purchase all or any portion of these reserved units, but any purchases they make will reduce the number of common units available to the general public. To the extent the allotted reserved units are not purchased in the directed unit program, we will offer these common units to the general public on the same basis as all other common units offered by this prospectus. The individuals eligible to participate in the directed unit program must commit to purchase no later than before the opening of business on the day following the date of this prospectus, but in any event, will not be obligated to purchase common units. Persons purchasing reserved units in the directed unit program will not be subject to a lock-up agreement. Chesapeake has agreed to indemnify Morgan Stanley & Co. LLC against certain liabilities and expenses, including liabilities under the Securities Act of 1933, in connection with the sales of the reserved units.

Notice to Prospective Investors in the EEA

In relation to each member state of the European Economic Area that has implemented the Prospectus Directive (each, a relevant member state), with effect from and including the date on which the Prospectus Directive is implemented in that relevant member state (the relevant implementation date), an offer of securities described in this prospectus may not be made to the public in that relevant member state other than:

- to any legal entity which is a qualified investor as defined in the Prospectus Directive;

- to fewer than 100 or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, 150, natural or legal persons (other than qualified investors as defined in the Prospectus Directive), as permitted under the Prospectus Directive, subject to obtaining the prior consent of the relevant Dealer or Dealers nominated by the Issuer for any such offer; or

- in any other circumstances falling within Article 3(2) of the Prospectus Directive;

provided that no such offer of securities shall require us or any underwriter to publish a prospectus pursuant to Article 3 of the Prospectus Directive.

For purposes of this provision, the expression an offer of securities to the public in any relevant member state means the communication in any form and by any means of sufficient information on the terms of the offer and the securities to be offered so as to enable an investor to decide to purchase or subscribe for the securities, as the expression may be varied in that member state by any measure implementing the Prospectus Directive in that member state, and the expression Prospectus Directive means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member State), and includes any relevant implementing measure in the Relevant Member State, and includes any relevant implementing measure in each relevant member state. The expression 2010 PD Amending Directive means Directive 2010/73/EU.

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We have not authorized and do not authorize the making of any offer of securities through any financial intermediary on their behalf, other than offers made by the underwriters with a view to the final placement of the securities as contemplated in this prospectus. Accordingly, no purchaser of the securities, other than the underwriters, is authorized to make any further offer of the securities on behalf of us or the underwriters.

Notice to Prospective Investors in the United Kingdom

The trust may constitute a collective investment scheme as defined by section 235 of the Financial Services and Markets Act 2000 (FSMA) that is not a recognized collective investment scheme for the purposes of FSMA (CIS) and that has not been authorized or otherwise approved. As an unregulated scheme, it cannot be marketed in the United Kingdom to the general public, except in accordance with FSMA. This prospectus is only being distributed in the United Kingdom to, and is only directed at:

(1) if the trust is a CIS and is marketed by a person who is an authorized person under FSMA, (a) investment professionals falling within Article 14(5) of the Financial Services and Markets Act 2000 (Promotion of Collective Investment Schemes) Order 2001, as amended (the CIS Promotion Order) or (b) high net worth companies and other persons falling within Article 22(2)(a) to (d) of the CIS Promotion Order; or

(2) otherwise, if marketed by a person who is not an authorized person under FSMA, (a) persons who fall within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the Financial Promotion Order) or (b) Article 49(2)(a) to (d) of the Financial Promotion Order; and

(3) in both cases (1) and (2) to any other person to whom it may otherwise lawfully be made (all such persons together being referred to as relevant persons).

The common units are only available to, and any invitation, offer or agreement to subscribe, purchase or otherwise acquire such common units will be engaged in only with, relevant persons. Any person who is not a relevant person should not act or rely on this document or any of its contents.

An invitation or inducement to engage in investment activity (within the meaning of Section 21 of FSMA) in connection with the issue or sale of any common units which are the subject of the offering contemplated by this prospectus will only be communicated or caused to be communicated in circumstances in which Section 21(1) of FSMA does not apply to the trust.

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LEGAL MATTERS

Richards, Layton & Finger, P.A., as special Delaware counsel to the trust, will give a legal opinion as to the validity of the common units. Bracewell & Giuliani LLP, counsel to Chesapeake, will give opinions as to certain other matters relating to the offering, including the tax opinion described in the section of this prospectus captioned U.S. Federal Income Tax Considerations beginning on page 95. Commercial Law Group, P.C. will pass upon certain other matters for Chesapeake. Certain legal matters in connection with the common units offered hereby will be passed upon for the underwriters by Baker Botts L.L.P., Houston, Texas.

EXPERTS

Certain information appearing in this prospectus regarding the June 30, 2011 estimated quantities of reserves of the Underlying Properties and royalty interests owned by the trust, the future net revenues from those reserves and their present value is based on estimates of the reserves and present values prepared by or derived from estimates prepared by Ryder Scott Company, L.P., independent petroleum engineers.

Certain estimates of Chesapeake s proved reserves of oil and natural gas that are incorporated by reference in this prospectus were based in part upon engineering reports prepared by independent petroleum engineers Ryder Scott Company, L.P., Netherland, Sewell & Associates, Inc., Data and Consulting Services, a division of Schlumberger Technology Corporation, and Lee Keeling and Associates, Inc. These estimates are referred to or incorporated by reference herein in reliance on the authority of such firms as experts in such matters.

The financial statements of Chesapeake and management s assessment of the effectiveness of internal control over financial reporting (which is included in Management s Report on Internal Control over Financial Reporting) incorporated in this prospectus by reference to Chesapeake s Annual Report on Form 10-K for the year ended December 31, 2010 have been so incorporated in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The Statements of Revenues and Direct Operating Expenses of the Chesapeake Colony Granite Wash Underlying Properties for the years ended December 31, 2008, 2009 and 2010, included in this prospectus, have been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The Statement of Assets and Trust Corpus of Chesapeake Granite Wash Trust as of June 30, 2011, included in this prospectus, has been so included in reliance on the report of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

WHERE YOU CAN FIND MORE INFORMATION

The trust and Chesapeake have filed with the SEC a registration statement on Form S-1 and Form S-3, respectively, regarding the common units. This prospectus does not contain all of the information found in the registration statement. For further information regarding the trust, Chesapeake and the common units offered by this prospectus, you may wish to review the full registration statement, including its exhibits and schedules, filed under the Securities Act. The registration statement of which this prospectus forms a part, including its exhibits and schedules, may be inspected and copied at the public reference room maintained by the SEC at 100 F Street, N.E., Washington, D.C. 20549. Copies of the materials may also be obtained from the SEC at prescribed rates by writing to the public reference room maintained by the SEC at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the public reference room by calling the SEC at 1-800-SEC-0330. The SEC maintains a website on the Internet at *http://www.sec.gov*. The trust s and Chesapeake s registration statement, of which this prospectus constitutes a part, can be downloaded from the SEC s web site.

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Chesapeake files annual, quarterly and current reports, proxy statements and other information with the SEC (File No. 001-13726) pursuant to the Exchange Act. Chesapeake s SEC filings are available to the public through the SEC s website. The trust will file annual, quarterly and current reports and other information with the SEC following its initial public offering.

This prospectus includes through incorporation by reference certain of the reports and other information that Chesapeake has filed with the SEC. This means that Chesapeake is disclosing important information to you by referring to those documents. Chesapeake hereby incorporates by reference into this prospectus the documents listed below that Chesapeake has filed with the SEC and any future filings that it makes with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act (excluding any information furnished under Item 2.02 or Item 7.01 on any Current Report on Form 8-K) prior to the later of (i) the closing date of the offering and (ii) the completion of the offering of the common units, which will automatically update and supersede information in this prospectus:

Chesapeake s Annual Report on Form 10-K for the year ended December 31, 2010, filed with the SEC on March 1, 2011;

Chesapeake s Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011, filed with the SEC on May 10, 2011, and June 30, 2011, filed with the SEC on August 9, 2011; and

Chesapeake s Current Reports on Form 8-K filed with the SEC on January 24, 2011, February 3, 2011, February 9, 2011, February 22, 2011, February 25, 2011, March 7, 2011, April 5, 2011, April 8, 2011, April 29, 2011, May 5, 2011, May 19, 2011, June 9, 2011, June 16, 2011, August 4, 2011 and September 23, 2011.

Chesapeake s recent annual, quarterly and current reports, and any amendments thereto, that it files with the SEC are made available, free of charge, over the Internet through Chesapeake s website at *www.chk.com* as soon as reasonably practicable after Chesapeake electronically files them with or furnishes them to the SEC. Please note that Chesapeake s website and the information contained in and linked to it are not incorporated in this prospectus.

Chesapeake will provide without charge to each person to whom this prospectus is delivered, upon written or oral request of such person, a copy of any or all documents incorporated by reference in this prospectus. Requests for such copies should be directed to Chesapeake at the following address and telephone number:

Jennifer M. Grigsby

Senior Vice President, Treasurer and Corporate Secretary

Chesapeake Energy Corporation

6100 North Western Avenue

Oklahoma City, Oklahoma 73118

Telephone: (405) 848-8000

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GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS AND TERMS RELATED TO THE TRUST

In this prospectus the following terms have the meanings specified below.

Area of Mutual Interest or *AMI*. Area within the Colony Granite Wash formation identified in the inside front cover of this prospectus.

bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

bcf. Billion cubic feet.

bbtu. One billion btu.

bcfe. Billion cubic feet of natural gas equivalent, determined using a ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

boe. A boe is determined using the ratio of six mcf of natural gas to one bbl of oil, condensate or natural gas liquids, which approximates the relative energy content of oil, condensate and natural gas liquids as compared to natural gas. Despite holding the ratio constant at six mcf to one bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned.

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at the original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

Developed acreage. The number of acres assignable to productive wells.

Development Area. The sections adjacent to governmental sections in the AMI.

Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (ii) drill and equip Development Wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (iii) acquire, construct and install production facilities such as leases, flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (iv) provide improved recovery systems.

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

Dry well. A well that proves to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue is determined at the terminal point of oil and gas producing activities as defined in Rule 4-10(a)(16) of Regulation S-X under the Securities Act.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays or areas of interest.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal wells. Wells which are drilled at angles greater than 70 degrees from vertical.

mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

mboe. One thousand boe.

mcf. One thousand cubic feet.

mcfe. One thousand cubic feet of natural gas equivalent, determined using a ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

mmboe. One million boe.

mmbtu. One million btus.

mmcf. One million cubic feet.

mmcfe. One million cubic feet of natural gas equivalent, determined using a ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or gross wells, as the case may be.

Net revenue interest. A share of production after all burdens, such as royalty and overriding royalty interests, have been deducted from the working interest.

NYMEX. New York Mercantile Exchange.

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

Present value of future net revenues (PV-10). 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.

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Production expenses.

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

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

(B) Repairs and maintenance.

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

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

(E) Severance taxes.

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

Producing well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

Productive well. A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

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

Proved reserves. Proved natural gas and oil reserves are those quantities of natural gas and oil, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of a reservoir considered as proved includes (a) the area indentified by drilling and limited by fluid contacts, if any, and (b) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geoscience and engineering data. In the absence of information on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (a) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (b) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and

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costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped (PUD) reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

PV-10. See Present value of future net revenues.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reserves. Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Standardized Measure or standardized measure of discounted future net cash flows. The present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production expenses and future income tax expenses, discounted at 10% per annum to reflect timing of future cash flows and using the same pricing assumptions as were used to calculate PV-10. Standardized Measure differs from PV-10 because Standardized Measure includes the effect of future income taxes on future net revenues. Because the trust does not bear income taxes, PV-10 and standardized measure with respect to the Royalty Interests are the same.

tcfe. One trillion cubic feet of natural gas equivalent, determined using a ratio of six mcf of natural gas to one bbl of crude oil, condensate or natural gas liquids.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or natural gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

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Report of Independent Registered Public Accounting Firm

To Board of Directors and Shareholders of Chesapeake Energy Corporation:

We have audited the accompanying statements of revenues and direct operating expenses of the Chesapeake Granite Wash Underlying Properties, as defined in Note 1, for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of Chesapeake Energy Corporation s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the statements of revenues and direct operating expenses of the Underlying Properties are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the statements of revenues and direct operating expenses of the Underlying Properties. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the statements referred to above present fairly, in all material respects, the revenues and direct operating expenses of the Underlying Properties for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

The accompanying statements reflect the revenues and direct operating expenses of the Underlying Properties as described in Note 1 to the financial statements and are not intended to be a complete presentation of the financial position, results of operations or cash flows of the Underlying Properties.

/s/ PricewaterhouseCoopers LLP

Tulsa, Oklahoma

July 7, 2011

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CHESAPEAKE GRANITE WASH UNDERLYING PROPERTIES

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

(In thousands)

	Year Ended December 31,			Six Months Ended June 30,	
	2008	**2009**	**2010**	**2010**	**2011**
				(unaudited)	
Oil, natural gas liquids and natural gas revenues[a]	$ 159,798	$ 123,594	$ 168,347	$ 87,533	$ 80,374