CHESAPEAKE GRANITE WASH TRUST
Form 10-K
March 14, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K
[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended December 31, 2013
[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to .
Commission File No. 001-35343
Chesapeake Granite Wash Trust
(Exact name of registrant as specified in its charter)

Delaware	45-6355635
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A., Trustee Global Corporate Trust 919 Congress Avenue Austin, Texas	78701
(Address of principal executive offices)	(Zip Code)

(855) 802-1093
(Registrant's telephone number, including area code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Units Representing Beneficial Interests	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [ ] No [X]
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes [ ] No [X]
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [ ] No [ ]
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]
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.

Large accelerated filer [ ]	Accelerated filer [X]	Non-accelerated filer [ ]	Smaller reporting company [ ]
	(Do not check if a smaller reporting company)		

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

The aggregate market value of the 23,000,000 Common Units representing beneficial interests in Chesapeake Granite Wash Trust held by non-affiliates of the registrant, computed using the closing sale price of $15.41 on June 28, 2013, was approximately $354 million.

As of March 12, 2014, 35,062,500 Common Units and 11,687,500 Subordinated Units representing beneficial interests in Chesapeake Granite Wash Trust were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Listed below is the only document parts of which are incorporated herein by reference and the parts of this Annual Report into which the document is incorporated:

None

CHESAPEAKE GRANITE WASH TRUST
2013 ANNUAL REPORT ON FORM 10-K
TABLE OF CONTENTS

All references to “we,” “us,” “our,” or the “Trust” refer to Chesapeake Granite Wash Trust. The royalty interests conveyed on November 16, 2011 by Chesapeake from its interests in certain properties in the Colony Granite Wash formation in Oklahoma and held by the Trust are referred to as the “Royalty Interests.” References to “Chesapeake” refer to Chesapeake Energy Corporation and, where the context requires, its subsidiaries.

DISCLOSURES REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (“Annual Report”) includes “forward-looking statements” about the Trust and Chesapeake and other matters discussed herein that are subject to risks and uncertainties that are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this document, including, without limitation, statements under “Trustee’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 of Part II and “Risk Factors” in Item 1A of Part I and elsewhere herein regarding the proved oil, NGL and natural gas reserves associated with the properties underlying the Royalty Interests, the Trust’s or Chesapeake’s future financial position, business strategy, budgets, projected costs and plans and objectives for future operations, information regarding target distributions, statements pertaining to future development activities and costs, statements regarding the number of development wells to be completed in future periods and information regarding production and reserve growth are forward-looking statements. Actual outcomes and results may differ materially from those projected. Our forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “foresee,” “plan,” “target,” “should,” “intend” or other words that convey the uncertainty of future events or outcomes. These statements are based on certain assumptions made by the Trust, and by Chesapeake in light of its experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate under the circumstances. However, whether actual results and developments will conform with such expectations and predictions is subject to a number of risks and uncertainties, including the risk factors discussed in Item 1A of Part I of this Annual Report, which could affect the future results of the energy industry in general, and the Trust and Chesapeake in particular, and could cause those results to differ materially from those expressed in such forward-looking statements. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to or effects on Chesapeake's business and the Trust. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in such forward-looking statements. The Trustee relies on Chesapeake for information regarding the Royalty Interests, the Underlying Properties and Chesapeake itself. The Trust undertakes no obligation to publicly update or revise any forward-looking statements, except as required by applicable law.

GLOSSARY OF CERTAIN TERMS

In this Annual Report, the following terms have the meanings specified below. Other terms are defined in the text of this Annual Report.

AMI. The area of mutual interest, or AMI, lies within Washita County in western Oklahoma and is limited to the Colony Granite Wash formation in the area identified below, consisting of approximately 45,400 gross acres (28,700 net acres) held by Chesapeake as of December 31, 2013.

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

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

Btu. British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil, NGL and 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 which are allocated or assignable to producing wells or wells capable of production.

Developed Reserves. Developed 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 Area. The sections adjacent to governmental sections in the AMI.
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.
Development Well. As defined by the SEC, a development well is 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. For the purposes of the Trust and as used herein, references to “Development Wells” refer to the 118 horizontal development wells that, since July 1, 2011, have been or are to be drilled on properties held by Chesapeake in the AMI and in which the Trust has received or will receive an interest.
Dry Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as a natural gas or oil 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.
Estimated Future Net Revenues. Also referred to as “estimated future net cash flows.” The result of applying current prices of oil, natural gas and NGL to estimated future production from oil, natural gas and NGL proved reserves, reduced by estimated future expenditures, based on current costs to be incurred, in developing and producing the proved reserves, excluding overhead.
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.
GAAP. Generally accepted accounting principles in the United States.
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.
IRS. The Internal Revenue Service of the United States federal government.
Mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.
Mboe. One thousand boe.
Mcf. One thousand cubic feet.
Mmbtu. One million btus.
Mmcf. One million cubic feet.
Net Acres or Net Wells. The sum of the fractional working interest owned in gross acres or gross wells.
Net Revenue Interest. A share of production after all burdens, such as royalty and overriding royalty interests, have been deducted from the working interest.

Natural Gas Liquids (NGL). Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing or cycling plants. Natural gas liquids primarily include ethane, propane, butane, isobutene, pentane, hexane and natural gasoline.

NYMEX. New York Mercantile Exchange.

Plugging and Abandoning. 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. PV-10 is a non-GAAP financial measure and generally differs from the 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 Trust will not bear federal income tax expense, the PV-10 and Standardized Measure attributable to the Royalty Interests are the same. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Underlying Properties or the Royalty Interests. The Trust, Chesapeake and others in the oil and gas 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.

Price Differential. The difference in the price of natural gas or oil received at the sales point and the NYMEX price.

Producing Well. As defined by the SEC, a producing well is 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. For the purposes of the Trust and as used herein, references to "Producing Wells" refer to the 69 existing horizontal wells in which Chesapeake conveyed an interest to the Trust effective as of July 1, 2011.

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, NGL and natural 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) Production taxes.

(ii) Some support equipment or facilities may serve two or more oil and natural 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 natural gas produced along with production (lifting) costs identified above.

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

Prospectus. The Chesapeake Granite Wash Trust Prospectus dated November 10, 2011 and filed with the SEC on November 14, 2011 in connection with the initial public offering of the Trust's common units.

Proved Developed Reserves. Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

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 (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible 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 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 elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price 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 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 are limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. 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.”

Reserves. Estimated remaining quantities of oil and natural 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 of Discounted Future Net Cash Flows. The discounted future net cash flows relating to proved reserves based on the prices used in estimating the proved reserves, year-end costs and statutory tax rates (adjusted for permanent differences) and a 10% annual discount rate. 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.

Undeveloped Acreage. Acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and 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.

PART I
ITEM 1. Business

Introduction
Chesapeake Granite Wash Trust is a statutory trust formed in June 2011 under the Delaware Statutory Trust Act pursuant to an initial trust agreement by and among Chesapeake, as Trustor, The Bank of New York Mellon Trust Company, N.A., as Trustee (the “Trustee”), and The Corporation Trust Company, as Delaware Trustee (the “Delaware Trustee”). The Trust maintains its offices at the office of the Trustee, which is located at 919 Congress Avenue, Suite 500, Austin, Texas 78701, and the telephone number of the Trustee is (855) 802-1093.
The Trustee maintains a website for filings by the Trust with the Securities and Exchange Commission (the “SEC”). Electronic filings by the Trust with the SEC are available free of charge through the Trust's website at www.chkgranitewashtrust.com or through the SEC's website at www.sec.gov. The Trust will also provide electronic and paper copies of its recent filings free of charge upon request to the Trustee.
General
The Trust was created to own the Royalty Interests for the benefit of Trust unitholders pursuant to a trust agreement dated as of June 29, 2011 and subsequently amended and restated as of November 16, 2011 by and among Chesapeake, Chesapeake Exploration, L.L.C., a wholly owned subsidiary of Chesapeake, the Trustee and the Delaware Trustee (the “Trust Agreement”). The Royalty Interests are derived from Chesapeake's interests in specified oil and natural gas properties located in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma (the “Underlying Properties”). Chesapeake conveyed the Royalty Interests to the Trust from Chesapeake's interests in the Producing Wells and the Development Wells.
The business and affairs of the Trust are managed by the Trustee. The Trust Agreement limits the Trust's business activities generally to owning the Royalty Interests and any activity reasonably related to such ownership, including activities required or permitted by the terms of the conveyances related to the Royalty Interests and derivative contracts between the Trust and its counterparty. 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 certain post-production expenses and any applicable taxes) from the sales of oil, NGL and natural gas production 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 certain post-production expenses and any applicable taxes) from the sales of oil, NGL and natural gas production attributable to Chesapeake's net revenue interest in the Development Wells.
Through an initial public offering in November 2011, the Trust sold to the public 23,000,000 common units, representing beneficial interests in the Trust, for cash proceeds of approximately $409.7 million, net of offering costs. The Trust delivered the net proceeds of the initial public offering, along with 12,062,500 common units and 11,687,500 subordinated units, to certain wholly owned subsidiaries of Chesapeake in exchange for the conveyance of the Royalty Interests to the Trust. Upon completion of these transactions, there were 46,750,000 Trust units issued and outstanding, consisting of 35,062,500 common units and 11,687,500 subordinated units. The common units and subordinated units have identical rights and privileges, except with respect to their voting rights and rights to receive distributions as described below under Target Distributions and Subordination and Incentive Thresholds.
The subordinated units are 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 80% of the target distribution for the corresponding quarter (the “subordination threshold”). If there is not sufficient cash to fund such a distribution on all of the Trust 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 the common units. In exchange for agreeing to subordinate a portion of its Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake is 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 (the “incentive threshold”). The remaining 50% of

cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. 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 for any subsequent quarter will

1

terminate. With respect to distributions for quarters following the fourth full quarter after Chesapeake's satisfaction of its Development Well drilling obligation, 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.

Neither the Trust nor the Trustee is responsible for, or has any control over, any costs related to the drilling of the Development Wells or any other operating or capital costs of the Underlying Properties. The Trust's cash receipts with respect to the Royalty Interests in the Underlying Properties are determined after deducting certain post-production expenses and any applicable taxes associated with the Royalty Interests. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, NGL and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by affiliates of Chesapeake. Cash distributions to unitholders will be increased or decreased by the effect of the Trust's derivative contracts and reduced by the Trust's general and administrative expenses. See Derivative Contracts below.

The Trust will dissolve and begin to liquidate on June 30, 2031, or earlier upon certain events (the “Termination Date”), and will soon thereafter wind up its affairs and terminate. At the Termination Date, (a) 50% of the total Royalty Interests conveyed by Chesapeake (the “Term Royalties”) will revert automatically to Chesapeake and (b) 50% of the total Royalty Interests conveyed by Chesapeake (the “Perpetual Royalties”) will be retained by the Trust and thereafter sold. The net proceeds of the sale of the Perpetual Royalties, as well as any remaining Trust cash reserves, will be distributed to the unitholders on a pro rata basis. Chesapeake will have a right of first refusal to purchase the Perpetual Royalties retained by the Trust at the Termination Date.

Target Distributions and Subordination and Incentive Thresholds

The Trust is required to make quarterly cash distributions of substantially all of its quarterly cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each quarter through (and including) the quarter ending June 30, 2031. Quarterly distributions to Trust unitholders will generally include royalty income attributable to sales of oil, NGL 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 first quarterly distribution was made on December 28, 2011 to record unitholders as of December 15, 2011.

In connection with the initial public offering of the Trust, Chesapeake established quarterly target levels of cash distributions to unitholders for the life of the Trust. These target distributions were used to calculate the subordination and incentive thresholds described in more detail below and do not represent estimates of the actual distributions that may be received by Trust unitholders. Actual cash distributions to the Trust unitholders will fluctuate quarterly based on the quantity of oil, NGL and natural gas sold from the Underlying Properties, the prices received for such sales, the timing of Chesapeake's receipt of payment for such sales, payments or receipts under the Trust's derivative contracts, the Trust's expenses and other factors. While target distributions initially increase as Chesapeake completes its drilling obligation and production increases, target distributions will decline over time as a result of the depletion of the reserves in the Underlying Properties.

Subordination Threshold. In order to provide support for cash distributions on the common units, Chesapeake agreed to subordinate 11,687,500 of the Trust units retained following the initial public offering of common units, which constitute 25% of the outstanding Trust units. The subordinated units are 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 80% of the target distribution for the corresponding quarter. 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.

Incentive Threshold. In exchange for agreeing to subordinate a portion of its Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake is 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. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to the Trust unitholders, including Chesapeake, on a pro rata basis.

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-

2

one basis and Chesapeake's right to receive incentive distributions for any subsequent quarter will terminate. With respect to distributions for quarters following the fourth full quarter after Chesapeake's satisfaction of its Development Well drilling obligation, 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. The period during which the subordinated units are outstanding is referred to as the subordination period.

The following table sets forth the subordination threshold and the incentive threshold for each calendar quarter through the second quarter of 2017, as established in the Trust Agreement:

Period	Subordination Threshold[(1)]	Incentive Threshold[(1)]
	($ per unit)	
2013:		
Fourth Quarter[(2)]	$0.69	$1.04
2014:		
First Quarter	$0.69	$1.04
Second Quarter	$0.68	$1.02
Third Quarter	$0.69	$1.03
Fourth Quarter	$0.66	$0.99
2015:		
First Quarter	$0.66	$0.99
Second Quarter	$0.68	$1.02
Third Quarter	$0.64	$0.96
Fourth Quarter	$0.56	$0.84
2016:		
First Quarter	$0.51	$0.76
Second Quarter	$0.47	$0.70
Third Quarter	$0.44	$0.66
Fourth Quarter	$0.41	$0.62
2017:		
First Quarter	$0.39	$0.59
Second Quarter	$0.37	$0.56

(1) For each quarter, the subordination threshold equals 80% of the target distribution and the incentive threshold equals 120% of the target distribution. The subordination and incentive thresholds terminate after the distribution is made for the fourth full calendar quarter following Chesapeake's completion of its drilling obligation.

(2) A distribution of $0.6624 per common unit was paid on March 3, 2014 to unitholders of record as of February 19, 2014. As the distribution per common unit was below the subordination threshold, no distribution was declared for the subordinated units.

For the year ended December 31, 2013, the Trust declared and paid the following cash distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
June 2013 - August 2013	November 29, 2013	$0.6671	$—
March 2013 - May 2013	August 29, 2013	$0.6900	$0.1432
December 2012 - February 2013	May 31, 2013	$0.6900	$0.3010
September 2012 - November 2012	March 1, 2013	$0.6700	$0.3772

As of March 12, 2014, Chesapeake owned 12,062,500 common units and all 11,687,500 subordinated units, which together represent 50.8% of the outstanding Trust units.

Derivative Contracts

The Trust uses derivative contracts in an effort to manage its exposure to variability in cash flow from changes in oil prices and, to the extent oil production falls below hedged oil volume, NGL prices. On November 16, 2011, Chesapeake novated to the Trust, and the Trust became party to, derivative contracts covering a portion of its expected production from October 1, 2011 through September 30, 2015. To the extent expected oil production falls below the hedged oil volume, the derivative contracts will also cover expected NGL production. To the extent oil and NGL prices are not correlated, the derivative contracts will not effectively mitigate the price risk of the Trust’s NGL production. The remaining estimated production of oil and NGL 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 derivative contract. The derivative contracts are not qualified for hedge accounting treatment, and therefore all future mark-to-market fluctuations will be recorded to the Trust Corpus until cash settled. The value of the derivative contracts as of December 31, 2013 was a liability of $8.1 million.

These derivative contracts consist of fixed-price oil swaps, in which the Trust receives a fixed price and pays a floating market price, based on NYMEX settlement prices, to the counterparty for the underlying commodity of the derivative. As a party to these contracts, the Trust receives payments directly from its counterparty or is required to pay any amounts owed directly to its counterparty. All swaps are net settled based on the difference between the fixed-price payment and the floating-price payment. Settlements are due on a quarterly basis, including the first two months of the calendar quarter just ended and the last month of the calendar quarter prior to that one. Any payment due to or from such counterparty will be made by the 40th day following the end of the calendar quarter in which such payments become due. See Note 3 to the financial statements contained in Part II, Item 8 of this Annual Report for further discussion of the derivative contracts.

Under the derivative contracts and separate from the drilling obligation under the development agreement, there is a requirement that Chesapeake drill and complete, or cause to be drilled and completed, a specified number of wells (inclusive of the Producing Wells as of the completion of the initial public offering and Development Wells) by the end of each six-month period ending June 30 and December 31 during the term of the derivative contracts. Specifically, from November 16, 2011 until June 30, 2016, the derivative contracts require that Chesapeake drill and complete, cause to be drilled and completed or participate as a non-operator in the drilling of 117 wells. As of December 31, 2013, Chesapeake had drilled and completed 144 wells and had fulfilled the cumulative minimum well requirement under the derivative contracts.

With respect to each such six-month period ending June 30 and December 31 during the term for the derivative contracts, the Trust is required to deliver to the counterparty and the collateral agent under the derivative contracts (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 obligations to the counterparty under the derivative contracts are secured by proved reserves attributable to the Trust's interest in the Underlying Properties. The counterparty's obligations under the derivative contracts must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts owed to the Trust exceed defined thresholds. 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 requirements under the derivative contracts, becomes subject to bankruptcy proceedings or the Trust becomes subject to certain change of control transactions, the derivative counterparty may foreclose on the lien on the Royalty Interests. Even if such foreclosure is solely a result of Chesapeake's action or omission, the Trust will have no remedy against Chesapeake. In addition, the derivative contracts 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 Trustee or the Delaware Trustee. Under the Trust Agreement, the Trustee may create a cash reserve to pay for future expenses of the Trust.

Administrative Services Agreement

On November 16, 2011, the Trust entered into an administrative services agreement with Chesapeake, effective July 1, 2011, pursuant to which Chesapeake provides the Trust with certain accounting, tax preparation, bookkeeping and information services related to the Royalty Interests and the registration rights agreement. In return for the services provided by Chesapeake under the administrative services agreement, the Trust pays Chesapeake an annual fee of

$200,000, which is paid in equal quarterly installments and remains fixed for the life of the Trust. Chesapeake is also 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.

Additionally, the administrative services agreement established Chesapeake as the Trust's hedge manager, pursuant to which Chesapeake has the authority, on behalf of the Trust, to administer the Trust's derivative contracts. As hedge manager, Chesapeake also has authority to terminate, restructure or otherwise modify all or any portion of the Trust's derivative contracts to the extent that Chesapeake reasonably determines, acting in good faith, that the volumes hedged under such contracts exceed, or are expected to exceed, the combined estimated production attributable to the Royalty Interests over the periods hedged. However, in fulfilling its role as hedge manager, Chesapeake is not acting as a fiduciary for the Trust and has no affirmative duty to modify any of the Trust's derivative contracts, except as required by the derivative contracts. Moreover, under the Trust Agreement, Chesapeake is indemnified by the Trust for any actions it takes in this regard.

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.

Description of the Trust

Common Units and Subordinated 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. The Trust has 46,750,000 Trust units issued and outstanding, consisting of 35,062,500 common units and 11,687,500 subordinated units. The common units and subordinated units have identical rights and privileges, except with respect to their voting rights and rights to receive distributions.

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 and Income Computations. The Trust is required to make quarterly cash distributions to unitholders from its available funds for such calendar quarter. Royalty Interest payments due to the Trust with respect to any calendar quarter are based on actual sales volumes attributable to the Trust's interests in the Underlying Properties (as measured at Chesapeake's metering systems) for the first two months of the quarter just ended as well as the last month of the immediately preceding quarter and actual revenues received for such volumes. Chesapeake makes the Royalty Interest payments to the Trust within 35 days of the end of each calendar quarter. In addition, any payments due from or required to be made to the counterparty under the Trust's derivative contracts are paid within 40 days of the end of such calendar quarter. Taking into account the receipt and disbursement of all such amounts, the Trustee determines 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 are reduced by any cash the Trustee decides to hold as a reserve against future liabilities.

The Trustee distributes cash approximately 60 days (or the next succeeding business day following such day if such day is not a business day) following each calendar quarter to each person who is 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 treats 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 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.

5

Transfer of Trust Units. Trust unitholders may transfer their Trust units in accordance with the Trust Agreement. The Trustee does 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.

Periodic Reports. The Trustee files all required Trust federal and state income tax and information returns. The Trustee prepares and mails to Trust unitholders a Schedule K-1 and also causes to be prepared and filed reports required to be filed under the Securities Exchange Act of 1934, as amended, and by the rules of the New York Stock Exchange.

Each Trust unitholder and his representatives have the right, at his own expense and during reasonable business hours upon reasonable prior notice, to examine and inspect the records of the Trust and the Trustee in reference thereto for any purpose reasonably related to the Trust unitholder's interest as a Trust unitholder.

Liability of Trust Unitholders. Under the Delaware Statutory Trust Act, Trust unitholders are 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 is 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 are 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);
- remove the Trustee or the Delaware Trustee;
- amend the Trust Agreement, the royalty conveyances, the administrative services agreement, the development agreement and the Drilling Support Lien (except with respect to certain matters that do not adversely affect the right of Trust unitholders in any material respect);
- merge, 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.

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.

Description of the Trust Agreement. 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 the Trust 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.

The Trust Agreement provides that the Trust's business activities are generally limited to owning the Royalty Interests, being a party to the derivative contracts and any 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 is not generally permitted to acquire other oil, NGL and natural gas properties or royalty interests. The Trust is not able to issue any additional Trust units.

Contractual Rights and Assets of the Trust. Contractual rights of the Trust include the development agreement, Drilling Support Lien and administrative services agreement. The assets of the Trust consist of the Royalty Interests, the derivative contracts and any cash and temporary investments being held for the payment of expenses and liabilities and for distribution to the Trust unitholders.

Duties and Powers 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 derivative contracts;
- 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).

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 derivative contracts. 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 withheld approximately $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”, 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 hedge manager for the Trust, may cause the Trust to restructure existing derivative contracts 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 is not liable for any act or omission of its agents or employees unless the Trustee acts 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 has a lien on the assets of the Trust as security for this indemnification and its compensation earned as Trustee. Trust unitholders are not liable to the Trustee for any indemnification. The Trustee is obligated to ensure that all contractual liabilities of the Trust are limited to the assets of the 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;
- 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.

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.

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.

Trust Fees and Expenses. The Trust is a party to derivative contracts and the Trust previously has had, and in the future 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, audit, 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 is also 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, are paid out of the Trust's assets.

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 dissolve and begin to liquidate on June 30, 2031, or earlier upon certain events, 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.

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.

Federal Income Tax Considerations

The Trust's federal income tax reporting position is that it is classified as a partnership for federal and applicable state income tax purposes. This position relies on the opinion of Bracewell & Giuliani L.L.P., counsel to Chesapeake and the Trust rendered in connection with the initial public offering of the Trust units, in which counsel opined that at least 90% of the Trust's gross income is qualifying income within the meaning of Section 7704 of the Internal Revenue Code of 1986, as amended. The Trust's federal income tax reporting positions are consistent with the Federal Income Tax Considerations section in the prospectus filed by the Trust with the SEC on November 14, 2011 in connection with the offering of its common units to the public (the “Federal Income Tax Considerations Section in the Prospectus”). However, as discussed in detail below under Item 1A. Risk Factors - Tax Risks Related to the Trust's Common Units, the Trust has not requested a ruling from the IRS regarding its United States federal income tax reporting positions and its positions may not be sustained by a court or if contested by the IRS.

Additional information regarding the opinion and material tax matters is discussed in the Federal Income Tax Considerations Section in the Prospectus.

Competition and Markets

The oil and gas industry is highly competitive. Chesapeake competes with both major integrated and other independent oil and 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 and gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied 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, NGL and natural gas production, such as changing prices, domestic and foreign policy 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 of oil, NGL and natural gas will directly impact Trust distributions, estimates of reserves attributable to the Trust's interest, and estimated and actual future net revenues to the Trust. In view of the many uncertainties that affect the supply and demand for oil, NGL and natural gas, neither the Trust nor Chesapeake can make reliable predictions of future supply and demand for oil, NGL and natural gas, future oil, NGL and natural gas prices or the effect of future oil, NGL and natural gas prices on the Trust.

Regulation

General

All of Chesapeake's operations are conducted onshore in the U.S. 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 administrative, civil and criminal penalties for non-compliance. These regulatory burdens increase Chesapeake's cost of doing business and, consequently, affect its profitability.

Although Chesapeake has advised the Trustee that Chesapeake believes it is in substantial compliance with all applicable laws and regulations, such laws and regulations could be, and frequently are, amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, Chesapeake is unable to predict the future costs or impacts of compliance or non-compliance. Additional proposals and proceedings that affect the natural gas and oil industry are regularly considered by Congress, the states, the local governments, the courts and federal agencies, such as the U.S. Environmental Protection Agency (EPA), the Federal Energy Regulatory Commission (FERC), the Department of Transportation (DOT), the Department of Interior and the Department of Energy. Chesapeake has advised the Trustee that Chesapeake actively monitors regulatory developments regarding the industry in order to anticipate and design required compliance activities and systems.

Exploration and Production

The laws and regulations applicable to Chesapeake's exploration and production operations include 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 such laws and regulations 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 oil and gas facilities are located, including the construction of well pads, pipelines, impoundments and associated access roads;
- water withdrawal;
- the plugging and abandoning of wells;
- the recycling or disposal of fluids used or other substances handled in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Chesapeake’s operations may require it to obtain permits for, among other things

- air emissions;
- construction activities, including in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- the construction and operation of underground injection wells to dispose of produced water 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.

Chesapeake's exploration and production activities 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, including Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas, West Virginia and Pennsylvania, 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 or controls less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from natural gas and oil wells, generally limit 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 natural gas and oil Chesapeake can produce and to limit the number of wells and the locations at which Chesapeake 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, NGL 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

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 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.

Chesapeake's operations are subject to stringent and complex federal, state and local laws and regulations relating to the protection of human health and safety, the environment and natural resources, which can restrict or impact its business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way Chesapeake can handle or dispose of wastes and other substances connected with operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- requiring investigatory and remedial actions to address pollution conditions caused by Chesapeake's operations or attributable to former operations;
- requiring noise mitigation, setbacks, landscaping, fencing, and other measures;
- prohibiting the operations of facilities deemed to be in non-compliance with permits issued pursuant to such environmental laws and regulations; and
- restricting access to certain equipment or areas to a limited set of employees or contractors who have proper certification or permits to conduct work (e.g., confined space entry and process safety maintenance requirements).

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures against Chesapeake, including the assessment of monetary penalties, the imposition of remedial or restoration obligations, and the issuance of orders enjoining future operations or imposing additional compliance requirements. Local land use restrictions, such as city ordinances, zoning laws, and traffic regulations, may restrict or prohibit the performance of well drilling in general or hydraulic fracturing in particular. Moreover, certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Chesapeake monitors developments at the federal, state and local levels to anticipate future regulatory requirements that might be imposed to reduce the costs of compliance with any such requirements and participates in industry groups that help formulate recommendations for addressing existing or future regulations and that share best practices and lessons learned in relation to pollution prevention and incident investigations.

Hazardous Substances and Waste

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 Chesapeake's operations, it generates petroleum hydrocarbon wastes such as produced water and ordinary industrial wastes. Under a longstanding legal framework, certain of these wastes are not subject to federal regulations governing hazardous wastes, although they are regulated under other federal and state waste 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, state and local laws may also require Chesapeake to remove or remediate previously disposed wastes or hazardous substances otherwise released into the environment, including wastes or hazardous substances 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 legally responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, persons who disposed of or arranged for the disposal of hazardous substances at the site and any person who accepted hazardous substances for transportation to 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.

The Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) program prohibits any underground injection unless authorized by a permit. Chesapeake recycles and reuses some produced water and also disposes of produced water in Class II UIC wells designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. Permits for Class II UIC wells may be issued by the EPA or by a state environmental agency if EPA has delegated its UIC Program authority.

Air Emissions

Chesapeake’s operations are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including Chesapeake’s compressor stations, and impose various monitoring and reporting requirements. Permits and related compliance obligations under the CAA, each state’s development and promulgation of regulatory programs to comport with federal requirements, and changes to state implementation plans for controlling air emissions in regional non-attainment or near-non-attainment areas may require natural gas and oil exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies.

In 2012, the EPA published final New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that amended the existing NSPS and NESHAP standards for oil and gas facilities and created new NSPS standards for oil and gas production, transmission and distribution facilities. While these rules remain in effect, the EPA announced in 2013 that it would reexamine and reissue the rules over the next three years. The EPA has issued updated rules regarding storage tanks and additional rules are expected. In 2010, the EPA published rules that require monitoring and reporting of greenhouse gas emissions from petroleum and natural gas systems. Chesapeake, along with other industry groups, filed suit challenging certain provisions of the rules and are engaged in settlement negotiations to amend and correct the rules. The EPA is also conducting a review of the National Ambient Air Quality Standards for ozone, but an expected completion date for that review is not currently known.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (CWA), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. The placement of material into jurisdictional water or wetlands of the U.S. is prohibited, except in accordance with the terms of a permit issued by the United States Army Corps of Engineers. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or a state agency delegated with EPA's authority. Further, Chesapeake's corporate policy prohibits discharge of produced water to surface waters. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture

or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The Oil Pollution Act of 1990 (OPA), establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S.

Health and Safety

The Occupational Safety and Health Act (OSHA) and comparable state laws regulate the protection of the health and safety of Chesapeake's employees. The federal Occupational Safety and Health Administration has established workplace safety standards that provide guidelines for maintaining a safe workplace in light of potential hazards, such as employee exposure to hazardous substances. OSHA also requires employee training and maintenance of records, and the OSHA hazard communication standard and EPA community right-to-know regulations under the Emergency Planning and Community Right-to-Know Act of 1986 require Chesapeake to organize and/or disclose information about hazardous materials used or produced in its operations.

Hydraulic Fracturing

Vast quantities of oil, NGL and natural gas deposits exist in deep shale and other unconventional formations. It is customary in Chesapeake's industry to recover these resources through the use of hydraulic fracturing combined with horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in deep underground formations using water, sand and other additives pumped under high pressure into the formation. As with the rest of the industry, Chesapeake uses hydraulic fracturing as a means to increase the productivity of almost every well that it drills and completes. These formations are generally geologically separated and isolated from fresh ground water supplies by thousands of feet of impermeable rock layers.

Chesapeake follows applicable legal requirements for groundwater protection in its operations that are subject to supervision by state and federal regulators. Furthermore, Chesapeake's well construction practices are performed in accordance with regulatory provisions which require the installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers and prevent the migration of fracturing fluids into freshwater aquifers.

Injection rates and pressures are monitored instantaneously and in real time at the surface during Chesapeake's hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations are shut down immediately if an abrupt change occurs to the injection pressure or annular pressure.

Hydraulic fracture stimulation requires the use of water. Chesapeake uses fresh water or recycled produced water in fracturing treatments in accordance with applicable water management plans and laws. Chesapeake strives to find alternative sources of water and to reduce its reliance on fresh water resources. Produced, or formation, water is a naturally occurring by-product of natural gas and liquids extraction. Chesapeake disposes of produced formation water in Class II underground injection control wells, which are designed in accordance with regulatory requirements and permitted to place the water into deep geologic formations, isolated from fresh water sources. These Class II wells are overseen by the EPA or states that have been delegated such authority pursuant to the Underground Injection Control Program. Additionally, Chesapeake has technical staff dedicated to the development of water recycling and re-use systems, and Chesapeake's Aqua Renew® program uses state-of-the-art technology in an effort to recycle produced water in its operations.

Hydraulic fracturing is typically regulated by state oil and gas commissions. Some states have adopted, and other states are considering adopting, regulations that impose disclosure requirements on hydraulic fracturing operations. Since early 2011, Chesapeake has participated in FracFocus, a national publicly accessible web-based registry developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission, with support of the U.S. Department of Energy, to report on a well-by-well basis the additives and chemicals and amount of water used in the hydraulic fracturing process for each of the wells Chesapeake operates. The website, www.fracfocus.org, also includes information about how hydraulic fracturing works, the chemicals used in hydraulic fracturing and how

14

fresh water aquifers are protected. Some states, including Oklahoma, mandate disclosure of chemical additives used in hydraulic fracturing and require operators to use the FracFocus website for reporting.

Legislative, regulatory and enforcement efforts and guidance from regulatory agencies 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. The EPA has asserted federal regulatory authority over hydraulic fracturing involving “diesel fuels” under the SWDA’s UIC Program and has released final guidance regarding the process for obtaining a permit for hydraulic fracturing involving diesel fuel. Chesapeake believes the guidance will not materially affect its operations, as it does not use diesel fuel in connection with its hydraulic fracturing. The EPA also has commenced a study of the potential impacts of hydraulic fracturing activities on drinking water resources, with a progress report released in late 2012 and a final draft report expected to be released for public comment and peer review in late 2014. In addition, the BLM published a revised draft of proposed rules that would impose new requirements on hydraulic fracturing operations conducted on federal and tribal lands, including the disclosure of chemical additives used in hydraulic fracturing operations. The EPA's guidance, including its interpretation of the meaning of “diesel fuel,” the EPA's pending study, BLM's proposed rules, and other analyses by federal and state agencies to assess the impacts of hydraulic fracturing could spur further action toward federal and/or state legislation and regulation of hydraulic fracturing activities.

Oklahoma's regulations were reviewed and received positive approval from the State Review of Oil & Natural Gas Environmental Regulations. Despite this finding, the Oklahoma Corporation Commission adopted amendments to its oil and natural gas rules that will require operators of hydraulically fractured wells to disclose the contents of fluids injected into each such well. The new disclosure rules became effective on July 1, 2012 and apply to horizontal wells hydraulically fractured after the end of 2012 and all wells hydraulically fractured after the end of 2013. As Chesapeake already discloses this information through FracFocus, these new requirements should not have a significant impact on the operation of the Underlying Properties. If additional 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 make it prohibitive for Chesapeake to conduct operations and also reduce the amount of oil, NGL and natural gas that Chesapeake is ultimately able to produce in commercial quantities from the Underlying Properties. For further discussion, see Item 1A Risk Factors - Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Endangered Species

The Endangered Species Act (ESA) restricts activities that may affect areas that contain endangered or threatened species or their habitats. While some of Chesapeake’s assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, it believes that it is in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where Chesapeake intends to conduct construction activity could materially limit or delay such plans. In addition, the imposition of seasonal restrictions on Chesapeake’s construction or operational activities could also materially limit or delay its plans.

Global Warming and Climate Change

Various state governments and regional organizations 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. 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, NGL 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 equipment and facilities, install new emission controls on equipment and facilities, acquire allowances to authorize greenhouse gas emissions, pay taxes related to 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, NGL and natural gas.

Operating Hazards and Insurance

The exploration and production business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these should occur, Chesapeake could incur legal defense costs and could suffer substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. Chesapeake's horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

As a passive entity, the Trust does not maintain insurance policies for the Underlying Properties. Chesapeake maintains a $75 million control of well policy that insures against certain sudden and accidental risks associated with drilling, completing and operating its wells. There is no assurance that this insurance will be adequate to cover all losses or exposure to liability. Chesapeake also carries a $460 million comprehensive general liability umbrella policy and a $150 million pollution liability policy. Chesapeake provides workers' compensation insurance coverage to employees in all states in which it operates. While Chesapeake has informed us that it believes these policies are customary in the industry, they do not provide complete coverage against all operating risks. In addition, Chesapeake's insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on Chesapeake's financial position, results of operations and cash flows. The insurance coverage that Chesapeake maintains may not be sufficient to cover every claim made against Chesapeake or may not be commercially available for purchase in the future.

The Underlying Properties and the Royalty Interests

Overview. The Underlying Properties consist of working interests owned by Chesapeake located in the Colony Granite Wash play in Washita County in western Oklahoma arising from leases and farmout agreements related to properties from which the Royalty Interests were conveyed. The AMI consists of approximately 45,400 gross acres (28,700 net acres). As of December 31, 2013 and 2012, the total reserves estimated to be attributable to the Trust were 18,502 mboe (45% oil and NGL by volume) and 28,203 mboe (46% oil and NGL by volume), respectively. These amounts include 12,640 mboe of proved developed reserves and 5,862 mboe of proved undeveloped reserves as of December 31, 2013 and 16,714 mboe of proved developed reserves and 11,489 mboe of proved undeveloped reserves as of December 31, 2012. The decrease in total reserves estimated to be attributable to the Trust of 9,701 mboe is primarily attributable to higher-than-expected pressure depletion within certain areas of the AMI. See Risk Factors - Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the Trust and the value of the Trust units in Item 1A and Risks and Uncertainties in Note 2 to the financial statements contained in Part II, Item 8 of this Annual Report for more information regarding pressure depletion.

The Colony Granite Wash is a subset of the greater granite wash plays of the Anadarko Basin. The Colony Granite Wash is located 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 NGL production currently 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 NGL than for natural gas. Development costs for horizontal wells drilled and completed in the AMI during the years ended December 31, 2013 and 2012 averaged approximately $19.68 per boe and $22.89 per boe, respectively, which are comparable to the development costs for other large-scale resource developments in the Mid-Continent in which Chesapeake operates. The decrease in average development costs of

$3.21 per boe is primarily due to a slight decrease in drilling costs.

16

Chesapeake began drilling horizontal wells in the Colony Granite Wash in 2007. As of December 31, 2013, Chesapeake is the largest leaseholder in the Colony Granite Wash, with approximately 43,200 net acres (of which approximately 28,700 net acres are subject to the Royalty Interests), the most active driller in the play, based on rig count, and produces the highest volumes from the Colony Granite Wash. Since 2007, there have been 258 Des Moines horizontal wells drilled in the Colony Granite Wash. Of those 258 wells, Chesapeake has drilled 201 wells and participated in another 49 wells. As of March 10, 2014, there were two rigs drilling horizontal wells in the AMI, both of which were operated by 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 typically equal to the production from several vertical wells. While Chesapeake is the most active company in this play, as of March 10, 2014, 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 Resources, Chaparral Energy, Inc. and Ward Petroleum Corporation.

Royalty Interests. The Royalty Interests were conveyed from Chesapeake's interest in the Underlying Properties effective as of July 1, 2011. As of December 31, 2013, the Trust on average owns a 47.6% net revenue interest in the Producing Wells and a 28.7% net revenue interest in the completed Development Wells. Chesapeake retains 10% of the proceeds from the sales of oil, NGL and natural gas production attributable to its net revenue interest in the Producing Wells, and 50% of the proceeds from the sales of production attributable to its net revenue interest in the Development Wells.

The Royalty Interests were conveyed to the Trust by Chesapeake by means of conveyance instruments that were recorded in the appropriate real property records in Washita County, Oklahoma. The conveyance instruments obligate Chesapeake 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." The Trustee has no ability to manage or influence the operation of the Underlying Properties.

Oil, NGL and Natural Gas Reserves. 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 net revenue 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.

All of the Trust's estimated oil, NGL and natural gas reserves are located within the U.S. The table below sets forth information as of December 31, 2013 with respect to the estimated proved reserves of the Underlying Properties and Royalty Interests and the associated PV-10. Because the Trust will not bear federal income tax expense, PV-10 and the standardized measure of estimated future net revenue of the Royalty Interests are the same. PV-10 is not intended to represent the current market value of the estimated oil, NGL and natural gas reserves attributable to the Royalty Interests. The reserve estimates were prepared by Ryder Scott Company, L.P. ("Ryder Scott") in accordance with the criteria established by the SEC.

	Proved Reserves				
	Oil (mbbl)	NGL (mbbl)	Gas (mmcf)	Total (mboe)	PV-10 (000s)
Underlying Properties:					
Developed	2,236	8,093	78,287	23,377	$297,935
Undeveloped	1,714	4,057	41,475	12,684	33,458
Total	3,950	12,150	119,762	36,061	$331,393
Royalty Interests:					
Developed[(1)]	1,274	4,339	42,161	12,640	$199,433
Undeveloped[(1)]	828	1,862	19,034	5,862	117,718
Total	2,102	6,201	61,195	18,502	$317,151

(1) PV-10 for the Royalty Interests was calculated exclusive of any production or development costs.

The proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil, NGL and natural gas for the period from January 1, 2013 through December 1, 2013, without giving effect to derivative contracts, 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. For the Royalty Interests, costs of marketing services provided by Chesapeake affiliates 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)	NGL (per bbl)	Natural gas (per mcf)
Trailing 12-month average (SEC) pricing	$ 96.82	$ 96.82	$ 3.67
Weighted average wellhead price (Underlying Properties)	$ 92.38	$ 31.68	$ 2.37
Weighted average wellhead prices (Royalty Interests)	$ 92.35	$ 31.86	$ 2.36

As of December 31, 2013, the reserve estimates for the Royalty Interests included 5,862 mboe of reserves classified as proved undeveloped ("PUD"), compared to 11,489 mboe as of December 31, 2012. Presented below is a summary of changes in our proved undeveloped reserves for 2013.

	Total (mboe)
Proved undeveloped reserves, beginning of period	11,489
Extensions, discoveries and other additions	993
Developed	(3,175)
Revisions of previous estimates	(3,445)
Proved undeveloped reserves, end of period	5,862

As of December 31, 2013, there were no PUDs that had remained undeveloped for five years or more. Chesapeake invested approximately $72 million in the Underlying Properties in 2013 to convert 7,052 (3,175 net to the Royalty Interests) mboe of PUDs to proved developed reserves. All costs were paid by Chesapeake as the Trust is not responsible for the cost of development. The downward PUD revisions of 3,445 mboe in 2013 included 880 mboe of downward performance-related revisions to PUD locations due to higher-than-expected pressure depletion in certain

18

areas of the AMI. In addition, there were 2,603 mboe of downward revisions related to the removal of PUDs that are not part of Chesapeake's five-year development plan within the AMI. Due to the higher-than-expected pressure depletion discussed above, Chesapeake reduced its operated rig count in the AMI from four rigs to two rigs in August 2013, which will allow more time to apply well performance analysis from well to well as Chesapeake's drilling program progresses at a slower pace. The downward revisions were offset by 38 mboe of upward price-related revisions.

The $118 million PV-10 attributable to the estimated PUDs of the Royalty Interests has been calculated assuming that Chesapeake will expend approximately $206 million to develop these reserves: $86 million in 2014, $98 million in 2015 and $22 million in 2016. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, availability of drilling and related services, service costs, commodity prices and the availability of capital. Chesapeake's developmental drilling schedule for the remaining Development Wells is subject to revision and reprioritization throughout the year resulting from unknowable factors such as rig availability, title issues or delays, and Chesapeake's net revenue interest in each Development Well when drilled and completed. The proved reserves as of December 31, 2013 include only PUD locations which are immediate offsets to producing wells. The annual net decline rate on producing properties is projected to be 36% from 2014 to 2015, 25% from 2015 to 2016, 20% from 2016 to 2017 and 14% from 2017 to 2018. As of December 31, 2013, of the total proved reserves, 23,377 mboe and 12,640 mboe attributable to the Underlying Properties and the Royalty Interests, respectively, were classified as proved developed producing.

Chesapeake's ownership interest used in calculating proved reserves and the associated estimated future net revenue was determined after giving effect to the assumed maximum participation by other parties to Chesapeake's farmout and participation agreements. The prices used in calculating the estimated future net revenues attributable to proved reserves are based on historical prices, as required by the SEC, and do not reflect market prices for oil, NGL and natural gas production sold subsequent to December 31, 2013. The estimated proved reserves may not be produced and sold at the assumed prices.

The Trust's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2013, along with the changes in quantities and standardized measure of such reserves since January 1, 2013, are shown in Supplemental Disclosures About Natural Gas, Oil, and NGL Producing Activities included in Item 8 of this Annual Report. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil, NGL and natural gas that cannot be measured in an exact way, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revisions to such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of oil, NGL and natural gas that are ultimately recovered. Furthermore, the estimated future net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate.

Development Wells. Pursuant to the development agreement with the Trust, Chesapeake is obligated to drill, cause to be drilled or participate as a non-operator in the drilling of 118 Development Wells by June 30, 2016. Additionally, based on Chesapeake's assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake retained or will retain an interest in each of the Producing Wells and Development Wells and, as of March 10, 2014, Chesapeake operated approximately 95% of the Producing Wells and the 79 completed Development Wells (approximately 87.9 Development Wells as calculated under the development agreement) and expects to operate 100% of the remaining Development Wells through the completion of its drilling obligation. Until such time as Chesapeake has met its commitment to drill the Development Wells, Chesapeake will not drill or complete, and will not permit any other person within its control to drill or complete: (i) any well in the Colony Granite Wash formation or lease acreage included within the AMI for its own account; or (ii) any well that will have a perforated segment within 600 feet of any perforated interval of any Development Well or Producing Well. Chesapeake's average net revenue interest in the oil and gas properties underlying the Development Royalty Interest is approximately 56%. The

Development Royalty Interest entitles the Trust to receive 50% of the proceeds attributable to Chesapeake's net revenue interest in future production of oil, NGL and natural gas resulting from the drilling of the Development Wells. Chesapeake is 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 receives proportionate credit. 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 less than 3,500 feet, Chesapeake may be required to drill more or less than 118 wells in order to fulfill its drilling obligation. As of December 31, 2013, Chesapeake had drilled and completed 75 wells within the AMI (approximately 82.4 Development Wells as calculated under the development agreement). Chesapeake's drilling activity with respect to the Development Wells is consistent with its intent to meet the drilling obligation contemplated by the development agreement. The current drilling schedule provides that approximately 15 wells are expected to be drilled and completed each year until the drilling obligation is fulfilled. As of March 10, 2014, Chesapeake had drilled and completed a total of 79 wells in the AMI (approximately 87.9 Development Wells as calculated under the development agreement) and had drilled, or caused to be drilled, two additional wells in the AMI that were awaiting completion.

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 remaining Development Wells will be generally consistent with those used for the Producing Wells and the completed Development Wells.

The Trust will not bear any of the costs of drilling, completing and equipping the Development Wells. Until Chesapeake has satisfied its drilling obligation, it will not be permitted to drill or complete any well in the Colony Granite Wash formation 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.

Chesapeake granted to the Trust a lien on its interest in the AMI (except the Producing Wells and any other wells that were already producing as of July 1, 2011 and are 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 could 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 are 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 is proportionately reduced. As of March 10, 2014, the total dollar amount that may be recovered is approximately $67.1 million.

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 Chesapeake's retained interest 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 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.

Well Locations. Chesapeake has approximately 80 remaining potential drilling locations within the AMI, based on assumed spacing of three 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.

Drilling Activity. The following table sets forth information with respect to the wells Chesapeake drilled or participated in during the periods indicated that were located in the AMI. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of reserves found. 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 interest owned in such gross wells.

	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Development productive	24	18	40	28	20	13
Exploratory productive	—	—	—	—	5	4
Dry	—	—	—	—	—	—
Total	24	18	40	28	25	17

Developed and Undeveloped Acreage. The following table sets forth information regarding developed and undeveloped acreage held by Chesapeake within the AMI as of December 31, 2013. A significant percentage 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	Net	Gross	Net
Acreage Held by Chesapeake within the AMI	40,236	26,195	830	830

(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.

(2) 830 net acres are not held by production as of December 31, 2013. Of these, 655 net acres will expire in 2014 and 175 net acres will expire in 2015. Chesapeake is not under any obligation to retain this acreage for development.

Prior to fulfilling its drilling obligation to the Trust, Chesapeake may, at its sole discretion, 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 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.

Marketing and Post-Production Services. Pursuant to the terms of the conveyances creating the Royalty Interests, Chesapeake has the responsibility to market, or cause to be marketed, the oil, NGL and natural gas production related to the Underlying Properties. While marketing costs of non-affiliates of Chesapeake are deducted from the proceeds upon which the royalty payments are calculated, the Trust is not responsible for costs of marketing services provided by Chesapeake or any of its affiliates. Chesapeake Energy Marketing, Inc. (“CEMI”), a wholly owned subsidiary of Chesapeake, markets the majority of Chesapeake's operated production. CEMI enters into oil, NGL 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, NGL 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. As a result, the proceeds to the Trust from the sales of oil, NGL and natural gas production from the Underlying Properties is determined based on the same price (net of post-production costs and production taxes) that Chesapeake receives from third parties for oil, NGL and natural gas production attributable to Chesapeake's remaining interest in the Underlying Properties.

21

Post-production expenses are deducted from proceeds paid to the Trust. Access Midstream Partners, L.P. ("ACMP"), successor to previously-affiliated Chesapeake Midstream Partners, L.P. (Chesapeake had a 46% equity investment until June 2012), provides gathering, treating, compression and other post-production services and other third parties, including Enogex LLC ("Enogex") and Freeport-McMoRan Copper & Gold ("FCX"), formerly known as Plains Exploration & Production Company, provide processing, transportation and other post-production services. The proceeds paid to the Trust are reduced by deductions for these post-production expenses.

Post-production expenses may be deducted by the ultimate purchaser of the oil, NGL and natural gas prior to payment being made to Chesapeake or CEMI for such production. At other times, Chesapeake or CEMI makes payments directly to the applicable provider of such post-production services. In either instance, the Trust's cash available for distribution is reduced by the expenses 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 post-production expenses are negotiated based on market conditions at the time or pursuant to a state or federal regulatory proceeding. Chesapeake is permitted to deduct from the proceeds available to the Trust other post-production expenses necessary to enhance the value of the oil, NGL and natural gas from the Underlying Properties and to transport such production to market.

Natural gas and NGL produced from the Underlying Properties are gathered by gathering pipelines owned by ACMP under a contract that expires in approximately 16 years. NGL 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 ACMP or transported by trucks owned by third parties and sold to FCX. In the event of a loss of its contracts with ACMP, Enogex or FCX, 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, NGL and natural gas from the Underlying Properties as currently contemplated.

Chesapeake has entered into, and expects to continue to enter into, oil, NGL and natural gas supply arrangements and post-production service arrangements for the oil, NGL and natural gas to be produced from the remaining Development Wells that are similar to those in place with respect to the Producing Wells and completed Development Wells. Any new oil, NGL 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.

Discussion and Analysis of Results from the Underlying Properties

Historical Results. 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 were conveyed. Chesapeake began drilling horizontal wells in the Colony Granite Wash in 2007.

The following table provides revenues and direct operating expenses for the years ended December 31, 2013, 2012 and 2011, as derived from the Underlying Properties' statements of revenues and direct operating expenses.

	Years Ended December 31,		
	2013	2012	2011
	($ in thousands)		
Oil, NGL and natural gas revenues[1]	$194,817	$176,875	$172,705
Direct operating expenses:			
Production expenses excluding taxes	13,747	12,835	8,252
Production taxes	2,544	2,437	3,887
Ad valorem taxes	66	43	43
Total direct operating expenses	16,357	15,315	12,182
Revenues in excess of direct operating expenses	$178,460	$161,560	$160,523

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

The following table sets forth the production, average sales prices, and average cost per boe for production expenses and production taxes for the Underlying Properties for the years ended December 31, 2013, 2012 and 2011.

	Years Ended December 31,		
	2013	2012	2011
Production:			
Oil (mbbls)	925	993	843
NGL (mbbls)	2,133	1,999	1,435
Natural gas (mmcf)	20,317	19,137	13,572
Total production (mboe)	6,444	6,182	4,540
Average sales prices:[1]			
Oil (per bbl)	$91.60	$90.42	$89.98
NGL (per bbl)	$31.05	$29.57	$42.09
Natural gas (per mcf)	$2.16	$1.46	$2.69
Direct operating expenses:			
Production expenses (per boe)[2]	$2.14	$2.08	$1.82
Production taxes (per boe)[3]	$0.39	$0.39	$0.86

(1) Average sales prices are net of post-production expenses, including gathering, storage, compression, transportation, processing, treating, dehydrating and non-affiliate marketing expenses.
(2) Production expenses include lease operating costs and ad valorem taxes.
(3) Production taxes are generally based upon (i) volume produced and (ii) prices received for production.

Oil, NGL and Natural Gas Revenues. For the year ended December 31, 2013, oil, NGL and natural gas revenues were $194.8 million compared to $176.9 million and $172.7 million for the years ended 2012 and 2011, respectively. The $17.9 million increase in revenues from 2012 to 2013 was primarily due to an increase in production of 262 mboe and an increase in oil, NGL and natural gas prices. Oil prices increased $1.18 per bbl, from $90.42 per bbl to $91.60 per bbl. NGL prices increased $1.48 per bbl, from $29.57 per bbl to $31.05 per bbl. Natural gas prices increased $0.70 per mcf, from $1.46 per mcf to $2.16 per mcf. The $4.2 million increase in revenue from 2011 to 2012 was primarily due to an increase in production of 1,642 mboe and a slight increase in oil prices of $0.44 per bbl, from $89.98 per bbl to $90.42 per bbl. These increases were partially offset by decreases in the average sales price for NGL and natural gas from $42.09 to $29.57 for NGL and from $2.69 to $1.46 for natural gas.

Production Expenses. For the year ended December 31, 2013, production expenses, excluding ad valorem taxes, were $13.7 million compared to $12.8 million and $8.3 million for the years ended 2012 and 2011, respectively. The year-over-year increases were primarily due to an increase in the number of producing wells. On a unit-of-production basis, production expenses, including ad valorem taxes, were $2.14 per boe in 2013 compared to $2.08 and $1.82 per boe in 2012 and 2011, respectively.

Production Taxes. For the year ended December 31, 2013, production taxes were $2.5 million compared to $2.4 million and $3.9 million for the years ended 2012 and 2011, respectively. On a unit-of-production basis, production taxes were $0.39 per boe in 2013 and 2012 compared to $0.86 per boe in 2011. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil, NGL and natural gas prices are higher. The $1.5 million decrease in production taxes from 2011 to 2012 was primarily due to a decrease in the average sales price for oil, NGL and natural gas from $38.04 to $28.61 per boe.

The Reserve Report for the Underlying Properties and the Royalty Interests

The oil, NGL and natural gas reserves in this Annual Report were estimated by Ryder Scott. The process to review and estimate the reserves began with Chesapeake's Corporate Reserves 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 Annual Report. Additionally, Chesapeake's senior management reviewed and approved the reserve report contained herein.

Internal Controls. Chesapeake's Director - Corporate Reserves is the technical person primarily responsible for overseeing the preparation of the Trust's reserve estimates. His qualifications include the following:

- 16 years of practical experience in petroleum engineering with 8 years of this experience being in the estimation and evaluation of reserves;
- Bachelor of Science degree in Chemical Engineering; and
- member in good standing of the Society of Petroleum Engineers.

Chesapeake ensures that the key members of Chesapeake's Corporate Reserves Department have appropriate technical qualifications to oversee the preparation of reserves estimates, including, with respect to its engineers, a minimum of an undergraduate degree in petroleum, mechanical or chemical engineering or other applicable technical discipline from an accredited university. With respect to its engineering technicians, a minimum of a four-year degree in mathematics, economics, finance or other business/science field. Chesapeake also maintains a continuous education program for its engineers and technicians on new technologies and industry advancements and offer refresher training on basic skill sets.

Chesapeake maintains internal controls such as the following to ensure the reliability of reserves estimations:

- 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.
- Chesapeake's Corporate Reserves Department reviews all of Chesapeake's and the Trust's reported proved reserves at the close of each quarter.
- Each quarter, Chesapeake's Corporate Reserves Department managers, the Director of Corporate Reserves, the Vice Presidents of its business units, the Senior Vice Presidents of its operating divisions and the Senior Vice President of Corporate and Strategic Planning review all significant reserves changes and all new proved undeveloped reserves additions.
- Chesapeake's Corporate Reserves Department reports independently of Chesapeake's operating divisions.

Technologies. The reserve report was prepared using decline curve analysis to determine the reserves of individual Producing Wells. After estimating the reserves of each proved developed well, it was determined that a reasonable level of certainty exists with respect to the reserves that can be expected from close offset undeveloped wells in the field. The continuity of the play across the AMI area was established by reviewing electronic well logs from wells, geologically mapping the analogous reservoir and reviewing extensive production data from horizontal wells within the larger Colony Granite Wash area. The proved undeveloped locations within the AMI are offsets to the horizontal wells drilled and producing as of December 31, 2013.

Ryder Scott. Ryder Scott, the independent petroleum engineering consultant, estimated all of the proved reserve information in this Annual Report, in accordance with the definitions and regulations of the SEC to conform with the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas. For purposes of the reserve report, a copy of which is filed with this Annual Report as Exhibit 99.1, 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 report have been estimated using such deterministic methods. Ryder Scott used standard engineering and geosciences methods, or a combination of methods, including 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: over 30 years of practical experience in the estimation and evaluation of petroleum reserves; a registered professional engineer in the state of Texas; a Bachelor of Science degree in Electrical Engineering; and a member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. 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.

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 is 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 outstanding Trust 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 votes 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.

ITEM1A. Risk Factors

Risks Related to the Units

Drilling for and producing oil, NGL 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, NGL and natural gas production. Drilling for oil, NGL 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 and the costs of drilling, completing and operating wells are often uncertain before drilling commences. 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, NGL and natural gas water or drilling fluids;
- natural disasters;
- environmental hazards, such as oil, NGL 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;
- reductions in oil, NGL 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, NGL 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 sales of oil, NGL and natural gas. Historically, the markets for oil, NGL and natural gas have been volatile and they are likely to continue to be volatile. Wide fluctuations in oil, NGL and natural gas prices may result from relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and other factors that are beyond the control of the Trust and Chesapeake, including:

- regional, domestic and worldwide supplies of oil, NGL and natural gas, including U.S. inventories of natural gas and oil reserves;
- weather conditions;
- changes in the level of consumer and industrial demand;
- the price and availability of alternative fuels;
- the effectiveness of worldwide conservation and environmental measures;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- potential U.S. exports of oil and/or liquefied natural gas;
- the price and level of foreign imports;
- the nature and extent of domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil and gas producing regions; and
- domestic and global political and economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, NGL and natural gas price movements with any certainty. For oil, from 2007 through March 10, 2014, 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 March 10, 2014, the highest monthly NYMEX settled price was $13.11 per mmbtu and the lowest was $2.04 per mmbtu. In addition, the market price of oil, NGL and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil, NGL and natural gas for heating purposes during the winter season. Beginning in 2012, high levels of NGL and natural gas production resulted in lower prices for those commodities throughout 2012 and 2013.

Lower oil, NGL and natural gas prices will reduce proceeds to which the Trust is entitled and may ultimately reduce the amount of oil, NGL 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, NGL 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, NGL 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, NGL and natural gas in commercially economic quantities. This could result in termination of the portion of the Royalty Interests relating to the abandoned well or property, and Chesapeake would have no obligation to drill a replacement well. The volatility of oil, NGL and natural gas prices also reduces the accuracy of target distributions used to calculate the subordination and incentive thresholds. There can be no assurance that the Trust's derivative contracts will mitigate these risks.

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 Royalty Interests. The future production estimates are based on estimates of reserve quantities for the Underlying Properties. It is not possible to measure underground accumulations of oil, NGL and natural gas in an exact way. The process of estimating oil, NGL and natural gas reserves is complex and involves significant decisions and assumptions associated with geological, geophysical, engineering and economic data for each well.

Actual future production attributable to the Royalty Interests, oil, NGL and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, NGL and natural gas reserves most likely will vary from these estimates. Such variations may be significant and could materially affect reserve estimates. 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, NGL and natural gas based on factors and assumptions that include:

- assumptions required by the SEC;
- historical production from the area compared with production rates from other producing areas;
- oil, NGL and natural gas prices, production levels, btu content, operating expenses, transportation costs, production 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. During 2013 and 2012, the Trust recorded significant downward reserve revisions primarily due to current results being below expectations, primarily as a result of higher-than-expected pressure depletion within certain areas of the AMI. Future negative well performance or lower expected ultimate recovery could lead to further downward adjustments to our reserve estimates. 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.

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.

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 is obligated to drill and complete, or participate as a non-operator in the drilling and completion of, the Development Wells at its own expense. Chesapeake expects to operate 100% of the remaining Development Wells until the completion of its drilling obligation. As of March 10, 2014, Chesapeake operates 95% of the Producing Wells and completed Development Wells. The conveyances provide that Chesapeake is obligated to market, or cause to be marketed, the oil, NGL 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 Royalty Interests and its ultimate cash available for distribution is highly dependent on Chesapeake's performance.

28

Chesapeake's ability to perform these obligations will depend on its future financial condition, economic performance and access to capital, which in turn will depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

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 $67.1 million as of March 10, 2014, which is the estimated amount of the Trust's share of the costs of drilling the remaining 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 Royalty Interests in Development Wells. 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 Royalty Interests are pledged as collateral to the Trust's derivative counterparty, 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 Royalty Interests by the derivative counterparty. 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. A 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, NGL and natural gas at the same prices as Chesapeake was able to achieve.

In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed 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 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 conveyed 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.

Estimates of the target distributions to unitholders used to calculate the subordination thresholds and incentive thresholds were 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 used to calculate the subordination thresholds and incentive thresholds were established by Chesapeake, and Chesapeake did not seek or receive an opinion or report on such estimates from any independent accountants, financial advisers or third-party reserve engineers. Such estimates were based on assumptions about drilling, production, oil, NGL 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, NGL and natural gas production is sold at prices consistent with spot and settled NYMEX pricing for July through November 2011, monthly NYMEX forward pricing as of October 28, 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 2025) 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, as they have for natural gas. Additionally, these estimates assume that the Development Wells will be drilled on Chesapeake's then-anticipated schedule and the related Underlying Properties will achieve production volumes set forth in the reserve reports included in the Prospectus; 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, NGL 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."

Furthermore, neither the target distribution nor the subordination threshold for each quarter during the subordination period necessarily represents the actual cash distributions Trust unitholders will receive, as evidenced by recent distributions to common unitholders that have been below the subordination threshold. To the extent actual production volumes or sales prices of oil, NGL and natural gas continue to be lower than the assumptions used to generate the target distributions, the actual distributions Trust unitholders receive are expected to 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 assure that Trust unitholders will in fact receive any specified return on 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, 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 continue to receive a distribution that is below the subordination threshold.

Quarterly cash distributions are 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 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.

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 and complete, or cause to be drilled and completed, the equivalent of 118 Development Wells in the AMI, of which approximately 87.9 Development Wells (as calculated under the development agreement) had been drilled and completed as of March 10, 2014. Chesapeake has drilled, or caused to be drilled, two additional wells in the AMI that are awaiting completion as of March 10, 2014. Chesapeake owns a majority working interest in 100% of the locations on which it expects to drill the remaining Development Wells, and it expects to operate such wells during the subordination period. In order to satisfy its drilling obligation, Chesapeake may rely upon third-party operators to drill some of the Development Wells. A significant portion of these wells may be drilled by a single third-party 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 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 most of 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 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.

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, NGL 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, NGL 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.

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

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

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

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

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, NGL 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, NGL and natural

31

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.

The Underlying Properties' operations may be adversely affected by oilfield services shortages, pipeline and gathering system capacity constraints and various transportation interruptions.

Chesapeake relies heavily on third parties to meet its oil, NGL and natural gas gathering demand for products from the Underlying Properties following the sale of substantially all of its midstream business and most of its gathering assets in 2012 and 2013. Capital constraints could limit the construction of new pipelines and gathering systems by third parties. Until this new capacity is available, Chesapeake may experience delays in producing and selling oil, NGL and natural gas from the Underlying Properties. In such event, Chesapeake might have to shut in the Development Wells awaiting a pipeline connection or capacity and/or sell oil, NGL or natural gas production at significantly lower prices than those quoted on NYMEX or than Chesapeake currently projects, which would adversely affect the Trust's results of operations.

Additionally, a portion of the Trust's oil, NGL and natural gas production may be interrupted, or shut in, from time to time for numerous reasons, including weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes.

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 are operated for oil, NGL and natural gas production and are focused exclusively in the Colony Granite Wash in Washita County in the Anadarko Basin of 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, NGL 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 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, NGL and natural gas production from the Underlying Properties.

The amount of oil, NGL 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, NGL and natural gas to meet quality specifications of gathering lines or downstream transporters, excessive line pressure which prevents delivery or physical damage to the 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

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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 a title deficiency with respect to the Underlying Properties could reduce the value or render a property worthless, thus adversely affecting the distributions to unitholders. Chesapeake does not obtain title insurance covering oil, 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, sales of oil, NGL 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 natural 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 have any contractual ability to influence or control the field operations of, sales of oil, NGL and natural gas from, or future development of, the Underlying Properties.

The oil, NGL 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 natural 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, NGL and natural gas from the Underlying Properties. The oil, NGL and natural gas reserves attributable to the Underlying Properties are depleting assets, which means that the reserves of oil, NGL and natural gas attributable to the Underlying Properties will decline over time. As a result, the quantity of oil, NGL 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, NGL 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.

33

The Trust Agreement provides that the Trust's business activities are generally limited to owning the Royalty Interests and entering into the derivative contracts 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 is not permitted to acquire other oil and natural 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, NGL 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, NGL 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 production 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, NGL and natural gas and the benchmark price for oil, NGL 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.

The amount of cash available for distribution by the Trust will be reduced by post-production expenses and applicable taxes associated with the 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, NGL and natural gas (excluding costs of marketing services provided by Chesapeake);
- the Trust's share of applicable taxes on the oil, NGL 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 amount owed to the counterparty under the Trust's derivative contracts.

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.

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. Historical post-production expenses and taxes, however, may not be indicative of future post-production expenses and taxes.

The derivative contracts for the Trust cover only a portion of the production attributable to the Royalty Interests, such arrangements limit the Trust's ability to benefit from commodity price increases for hedged volumes, and such arrangements are secured by the Royalty Interests and may require the Trust to make cash payments in excess of its receipts.

The Trust hedged approximately 50% of the expected oil and NGL production and approximately 37% of the Trust's expected revenues (based on NYMEX strip oil prices as of October 28, 2011) for the production periods from

October 1, 2011 through September 30, 2015 under its derivative contracts. To the extent oil production falls below the hedged oil volume, the derivative contracts will also cover NGL production. Such estimated production will be hedged using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. Since late 2011, NGL prices have decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the derivative arrangements will not effectively mitigate the price risk of the Trust's NGL production. Except in limited circumstances involving the restructuring of existing derivative contracts, the remaining estimated production of oil and NGL 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 derivative contracts, terminate existing derivative contracts 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, NGL and natural gas, commodities that are frequently characterized by significant price volatility. Furthermore, while the use of derivative contracts limits the downside risk of price declines, they may also limit the Trust's ability to benefit from increases in oil and NGL prices above the fixed price of the derivative contract on the portion of the production attributable to the Royalty Interests that is hedged.
Chesapeake acts as hedge manager to the Trust pursuant to the administrative services agreement. In fulfilling its role as hedge manager, Chesapeake does not act as a fiduciary for the Trust, does not have an affirmative duty to modify any of the Trust's derivative contracts except as required by the derivative contracts, and does not have any liability to the Trust in connection with Chesapeake's failure to modify, or any affirmative modification of, any of the Trust's derivative contracts. 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 derivative contracts depends upon the financial position of the counterparty. If the counterparty to the derivative contracts was to default on its obligations to make payments under such contracts, the cash distributions to the Trust unitholders would likely be materially reduced as the derivative contract payments are intended to provide additional cash to the Trust during periods of lower oil and NGL prices.
If actual production, over which the Trust has no control, is below the amounts forecasted in the reserve reports and oil or NGL prices rise, the derivative contracts entered into by the Trust may result in the Trust having to make cash payments under the derivative contracts which could, in certain circumstances, be significant. Swap contracts entered into between the Trust and the counterparty provide the Trust with the right to receive from the counterparty the excess of the fixed-price specified in the derivative 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 the counterparty this difference in price multiplied by the volume of production hedged, even if the production attributable to the Royalty Interests is insufficient to cover the volume of production specified in the applicable derivative contracts. Accordingly, if the production attributable to the 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.
Under the derivative contracts, with respect to each six-month period ending June 30 and December 31 during the term of the derivative contracts, the Trust is required to deliver to the counterparty and the collateral agent under the derivative contracts an independent reserve engineers' report and a report that sets forth certain information regarding the Development Wells drilled and completed as of the end of such six-month period. The obligations to the counterparty under the derivative contracts are secured by the Royalty Interests. Subject to any applicable notice and cure periods, if, among other things, the Trust or Chesapeake is in material default of the payment or reporting requirements set forth in the derivative contracts, or becomes subject to bankruptcy proceedings or the Trust becomes subject to certain change of control transactions, the counterparty may foreclose on the lien on the Royalty Interests. Following foreclosure by the counterparty, the counterparty 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. Even if such foreclosure is solely a result of Chesapeake's action or omission, the Trust may have no remedy against Chesapeake. Such foreclosure would have a material adverse effect on the Trust's results of operations and ability to make distributions.

In addition, the Trust's derivative contracts prohibit the Trust from granting additional liens on any of its properties, other than customary permitted liens and liens in favor of the Trustees of the Trust.

The Trustee may, under certain circumstances, sell the Royalty Interests and dissolve the Trust; otherwise, the Trust will begin to liquidate following the end of the 20-year period in which the Trust owns the Term Royalties.

The Royalty Interests will be sold and the Trust will be dissolved upon the occurrence of certain events. For example, the Trustee must sell the Royalty Interests if unitholders approve the sale or vote to dissolve the Trust. The Trustee must also sell the Royalty Interests if cash available for distribution is less than $1.0 million in each of any four consecutive quarters. The sale of all of the Royalty Interests will result in the dissolution of the Trust. Upon the dissolution of the Trust, the net proceeds of any such sale, after the payment of Trust liabilities, will be distributed to the Trust unitholders pro rata and unitholders will not be entitled to receive any proceeds from the sale of production from the Underlying Properties following such date. If none of these events occur, the Trust will dissolve on the Termination Date.

In connection with the dissolution of the Trust on the Termination Date, the Term Royalties will automatically revert to Chesapeake, while the Perpetual Royalties will be sold and the proceeds will be distributed to the unitholders (including Chesapeake to the extent of any Trust units it owns) at the date the Trust dissolves or soon thereafter. The price received by the Trust from any purchaser of the Perpetual Royalties will depend, among other things, on the prices of oil, NGL and natural gas at that time. There can be no assurance that the prices of oil, NGL 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.

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 are managed by the Trustee. 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 Interest conveyances, 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 Royalty Interests. 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 under the development agreement and, to the fullest extent permitted by law, will owe no fiduciary duties to the Trust or the unitholders.

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

Under the Delaware Statutory Trust Act, Trust unitholders are 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.

Chesapeake owns an aggregate of 12,062,500 common units and 11,687,500 subordinated units. All of the subordinated units will automatically convert into common units at the end of the subordination 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 Trust units by Chesapeake to the public.

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, NGL 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, 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.
- 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.
- 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, NGL and natural gas development and production than Chesapeake.

Trust unitholders 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 under the development agreement 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 Royalty Interests. Any purchaser, farmout counterparty or participating partner could have a weaker financial position and/or be less experienced in oil, NGL 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 Interests will not burden any interests that the counterparty earns under such an agreement.

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

Oil and natural 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. Some of these risks or hazards could materially and adversely affect Chesapeake's revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of its prospects. A temporary or permanent halt of the production and sales of oil, NGL 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 an inherent risk of incurring significant environmental costs and liabilities in Chesapeake's operations due to the use, generation, handling and disposal of materials, including wastes, petroleum hydrocarbons and other chemicals. Chesapeake may incur joint and several, strict liability under applicable 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 oil and natural gas exploration and production activities for a number of years, often by third parties not under its control. Chesapeake also could incur material fines, penalties and government or third-party claims as a result of violations of, or liabilities under, applicable environmental laws and regulations. For non-operated properties, Chesapeake is dependent on the operator for operational and regulatory compliance.

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 $460 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

38

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. Additionally, Chesapeake is 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 does not have insurance or indemnification to protect against losses or delays in receiving proceeds from such events. Finally, in the future, Chesapeake may not be able to obtain insurance at premium levels that Chesapeake believes justifies its purchase.

The ability of the Underlying Properties to produce oil, NGL and natural gas economically and in commercial quantities could be impaired if Chesapeake is unable to acquire adequate supplies of water for its drilling operations or is unable to dispose of or recycle the water it uses economically and in an environmentally safe manner.

Development activities on the Underlying Properties require the use of water. For example, the hydraulic fracturing process that Chesapeake employs to produce commercial quantities of oil and natural gas from many reservoirs requires the use and disposal of significant quantities of water. In the AMI, there is insufficient local aquifer capacity to provide a source of water for drilling activities. Water must be obtained from other sources and transported to the drilling site. Chesapeake’s inability to secure sufficient amounts of water, or to dispose of or recycle the water used in its operations, could adversely impact development of the Underlying Properties. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on Chesapeake’s ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the exploration, development or production of natural gas and oil.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Several states are considering adopting, and some states have already passed, regulations that could impose more stringent permitting, public disclosure, and/or well construction requirements on hydraulic fracturing operations. For example, Pennsylvania is currently considering proposed regulations applicable to surface use at oil and gas well sites, including new secondary containment requirements and an abandoned and orphaned well identification program that would require operators to remediate any such wells that are damaged during current hydraulic fracturing operations. In addition to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. There are also certain governmental reviews either underway or being proposed that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate such activities. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

We cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed on hydraulic fracturing operations, Chesapeake's business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

Federal regulatory initiatives relating to air emissions could result in increased costs and additional operating restrictions or delays.

The EPA has published New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that amended existing NSPS and NESHAP standards for oil and gas facilities and created new NSPS standards for oil and gas production, transmission and distribution facilities. The EPA announced in 2013 that it would reexamine and reissue these rules over the next three years. It has issued updated rules regarding storage tanks, and additional rules are expected, but the outcome of this process remains uncertain. In addition, the EPA has issued rules requiring monitoring and reporting of greenhouse gas emissions from petroleum and natural gas systems. Chesapeake, along with other industry groups, filed suit challenging certain provisions of these rules, but the outcome of the challenge is uncertain and may impact Chesapeake's reporting obligations. The EPA is also conducting a review of the National Ambient Air Quality Standards for ozone, which could result in more stringent air emissions standards applicable to Chesapeake’s operations. An expected completion date for that review is not currently known.

Potential legislative and regulatory actions directed at climate change could increase Chesapeake's costs, and adversely affect the demand for oil, NGL and natural gas

Various state governments and regional organizations 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. 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, NGL 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 its greenhouse gas emissions, pay taxes related to greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Even without federal legislation or regulation of greenhouse gas emissions, states may pursue the issue either directly or indirectly. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for oil, NGL and natural gas.

If the Trust should need to restructure its derivative contracts, OTC derivatives regulation could increase the costs of restructuring and potentially have other adverse effects.

In July of 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 migrating over-the-counter (OTC) derivative markets to exchange-traded and cleared markets. Certain companies that use derivatives to hedge commercial risk, referred to as end-users, are permitted to continue to use OTC derivatives under newly adopted regulations. Chesapeake maintains an active price and basis risk management program related to the natural gas and oil it produces for its own account in order to manage the impact of low commodity prices and to predict future cash flows with greater certainty. Chesapeake used the OTC market for its fixed price oil swaps contracts that were novated to the Trust. Although the Trust is not permitted to enter into any new derivative contracts and may restructure its existing derivative contracts only in limited circumstances where production falls below hedged volumes, the Dodd-Frank Act and the rules and regulations promulgated thereunder could significantly increase the cost of restructuring the Trust's existing derivative contracts (including through requirements to post collateral which could adversely affect available liquidity of the Trust), reduce the Trust's ability to monetize or restructure its existing derivative contracts and increase the Trust's exposure to less creditworthy counterparties.

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

The Trust is subject to certain of the requirements of the Sarbanes-Oxley Act of 2002 which requires, 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

40

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.
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 Trust unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to Trust unitholders 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 Trust unitholders would be substantially reduced. In addition, changes in current state law may subject the Trust to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to Trust unitholders. Therefore, if the Trust were treated as a corporation for U.S. federal income tax purposes or otherwise subjected to a material amount of entity-level taxation, there would be 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.
The tax treatment of an investment in Trust units could be affected by recent and potential legislative changes, possibly on a retroactive basis.
In taxable years beginning after December 31, 2012, an individual having adjusted gross income in excess of $200,000 (or $250,000 for married taxpayers filing joint returns) is subject to the Net Investment Income Tax of 3.8% on the lesser of such excess or the individual's net investment income. For these purposes, net investment income generally includes interest income and royalty income derived from the Trust units as well as any net gain from the disposition of Trust units. In addition, beginning January 1, 2013, the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals is 39.6% and 20%, respectively. It has been assumed that the effective rate of production tax on the oil, NGL 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, from time to time, legislation is proposed that would affect partnership tax treatment for certain publicly traded partnerships. Any modification to the U.S. federal income tax laws and interpretations thereof could make it more difficult or impossible to meet the requirements for the Trust to be treated as a partnership for U.S. federal income tax purposes. Moreover, any modification to the U.S. federal income tax laws and interpretations thereof may be applied retroactively. The Trust is unable to predict whether any of these changes or any other proposals will ultimately be enacted. Any such legislation would likely also affect the Trust tax treatment for state tax purposes and could negatively impact the value of an

investment in Trust units.

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 to Trust unitholders.

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 the federal income tax considerations section in the prospectus or form 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 the 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.

Trust unitholders will be required to pay taxes on their share of the Trust's income even if they 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, Trust unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of the Trust's taxable income even if they receive no cash distributions from the Trust. Trust unitholders may not receive cash distributions from the Trust equal to their 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.

Trust unitholders that sell their Trust units will recognize a gain or loss equal to the difference between the amount realized and the tax basis in those Trust units. Because distributions in excess of the Trust unitholders allocable share of the Trust's net taxable income decrease the tax basis in such Trust unitholders' Trust units, the amount, if any, of such prior excess distributions with respect to the Trust units sold will, in effect, become taxable income if Trust units are sold at a price greater than the tax basis in those Trust units, even if the price received is less than the original cost of the Trust units. 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.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning the Trust units that may result in adverse tax consequences to them.

Investment in Trust units by tax-exempt entities, such as individual retirement accounts (known as IRAs), and non-U.S. persons raises issues unique to them. For example, some of the Trust income allocated to organizations exempt from United States federal income tax, including IRAs and other retirement plans, may be unrelated business taxable income which would be taxable to them. 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.

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 has adopted 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 the sale of Trust units by Trust unitholders and could have a negative impact on the value of the Trust units or result in audit adjustments to Trust unitholders tax returns.

The Trust prorates 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 prorates 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, although the United States Treasury Department issued proposed Treasury Regulations allowing a monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method the Trust has adopted. 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.

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

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

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

The Trust will be considered to have technically terminated for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in its capital and profits within a 12-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 if relief is not available) for one fiscal year. The IRS has 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.

43

Trust unitholders may be subject to state and local taxes and return filing requirements in jurisdictions where they 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. Trust unitholders will likely be required to file Oklahoma state income tax returns and pay Oklahoma state income tax. Further, Trust unitholders 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, NGL 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 2014 is the elimination of certain key U.S. federal income tax preferences relating to oil, NGL 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. These changes, if enacted, will make it more costly for Chesapeake to explore for and develop its oil and natural gas resources.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

Reference is made to "Item 1 - Business," which is incorporated herein by reference.

ITEM 3. Legal Proceedings

There are no legal proceedings to which the Trust is a party.

Chesapeake has advised the Trustee that Chesapeake is involved in various lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, various mineral or leasehold owners have filed lawsuits against Chesapeake seeking specific performance to require Chesapeake to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. Chesapeake has advised the Trustee that Chesapeake has successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal.

Chesapeake has advised the Trustee that at this time Chesapeake has three lawsuits in process that involve properties in the AMI and have claims that exceed $100,000 individually or in aggregate. The Trust is a not a party to any such lawsuit and Chesapeake has advised the Trustee that Chesapeake is not aware of any pending or threatened lawsuit or dispute that, individually or in the aggregate, is likely to have a material adverse effect on the Trust's financial position or distributable income.

ITEM 4. Mine Safety Disclosures

Not applicable.

PART II
ITEM 5. Market for Units of the Trust, Related Unitholder Matters and Trust Purchases of Units

Common Units Representing Beneficial Interests

The common units representing beneficial interests in the Trust are listed and commenced trading on the New York Stock Exchange on November 11, 2011 under the symbol “CHKR”. The following table sets forth, for the periods indicated, the high and low sales prices per common unit as reported by the New York Stock Exchange:

	Common Units	
	High	Low
First Quarter 2012 (January 1 through March 31)	$30.24	$20.78
Second Quarter 2012 (April 1 through June 30)	$26.88	$17.37
Third Quarter 2012 (July 1 through September 30)	$23.47	$19.60
Fourth Quarter 2012 (October 1 through December 31)	$21.41	$16.23
First Quarter 2013 (January 1 through March 31)	$19.15	$13.07
Second Quarter 2013 (April 1 through June 30)	$17.24	$14.10
Third Quarter 2013 (July 1 through September 30)	$16.60	$13.18
Fourth Quarter 2013 (October 1 through December 31)	$15.00	$9.90

As of December 31, 2013, 35,062,500 common units representing beneficial interests in Chesapeake Granite Wash Trust were outstanding and held by nine certified unitholders of record. Such units were issued on November 16, 2011. The following table sets forth, for the periods indicated, the common and subordinated distribution per unit:

	Distribution per Unit	
	Common Unit	Subordinated Unit
First Quarter 2012	$0.7277	$0.7277
Second Quarter 2012	$0.6588	$0.6588
Third Quarter 2012	$0.6100	$0.4819
Fourth Quarter 2012	$0.6300	$0.2208
First Quarter 2013	$0.6700	$0.3772
Second Quarter 2013	$0.6900	$0.3010
Third Quarter 2013	$0.6900	$0.1432
Fourth Quarter 2013	$0.6671	$—

Pursuant to the Trust Agreement, if at any time the Trust's cash on hand (including cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will loan 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 current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans 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.

Equity Compensation Plans

The Trust does not have any employees and, therefore, does not maintain any equity compensation plans.

Recent Sales of Unregistered Securities

On November 16, 2011, in connection with the initial public offering by the Trust of its common units, Chesapeake conveyed the PDP Royalty Interest and the Development Royalty Interest to the Trust in exchange for 12,062,500 common units, 11,687,500 subordinated units and $409.7 million in cash.

Purchases of Equity Securities

None.

ITEM 6. Selected Financial Data
Distributable Income
The following is a summary of royalty income, interest income and distributable income for the years ended December 31, 2013 and 2012 and the six months ended December 31, 2011 (in thousands except per unit amounts):

	Year Ended December 31, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
Royalty income	$114,010	$127,335	$29,334
Interest income	$—	$3	$2
Distributable income	$104,868	$116,510	$27,115
Distributable income per common unit	$2.7171	$2.6265	$0.5800
Distributable income per subordinated unit	$0.8214	$2.0892	$0.5800

Assets, Liabilities and Trust Corpus
The following is the balance of total assets, total liabilities and trust corpus as of December 31, 2013, 2012 and 2011 (in thousands except per unit amounts):

	December 31, 2013	2012	2011
Total Assets	$318,288	$429,621	$483,659
Total Liabilities	$8,071	$8,084	$20,741
Trust Corpus	$310,217	$421,537	$462,918

ITEM 7. Trustee's Discussion and Analysis of Financial Condition and Results of Operations
Introduction
The following discussion and analysis is intended to help the reader understand the Trust's financial condition and results of operations. This discussion and analysis should be read in conjunction with the audited financial statements and the accompanying notes relating to the Trust and the Underlying Properties included in Part II, Item 8 of this Annual Report and The Underlying Properties and the Royalty Interests and Discussion and Analysis of Results from the Underlying Properties included in Part I, Item 1 of this Annual Report.
Overview
The Trust is a statutory trust formed in June 2011 under the Delaware Statutory Trust Act. The business and affairs of the Trust are managed by the Trustee and, as necessary, the Delaware Trustee. The Trust does not conduct any operations or activities other than owning the Royalty Interests and activities related to such ownership. The Trust’s purpose is generally to own the Royalty Interests, to distribute to the Trust unitholders cash that the Trust receives in respect of the Royalty Interests and the derivative contracts (described in Note 3 to the financial statements contained in Part II, Item 8 of this Annual Report) and to perform certain administrative functions in respect of the Royalty Interests and the Trust units. The Trust derives all or substantially all of its income and cash flow from the Royalty Interests and the derivative contracts. The Trust is treated as a partnership for federal income tax purposes.
Concurrent with the Trust's initial public offering in November 2011, Chesapeake conveyed the Royalty Interests to the Trust effective July 1, 2011, which included interests in (a) 69 Producing Wells in the Colony Granite Wash play and (b) 118 Development Wells that have since been or that are to be drilled in the Colony Granite Wash play on properties within the AMI. Chesapeake is obligated to drill, cause to be drilled or participate as a non-operator in the drilling of the Development Wells from drill sites in the AMI on or prior to June 30, 2016. Additionally, based on Chesapeake’s assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. As of December 31, 2013, Chesapeake had drilled and completed 75 wells within the AMI (approximately 82.4 Development Wells as calculated under the development agreement). As of March 10, 2014, Chesapeake had drilled and completed, or caused to be

drilled and completed, a total of 79 wells within the AMI (approximately 87.9 Development Wells as calculated under the development agreement) and had drilled, or caused to be drilled, two additional wells within the AMI that were awaiting completion.

The Trust is not responsible for any costs related to the drilling of the Development Wells or any other operating or capital costs of the Underlying Properties, and Chesapeake is not permitted to drill and complete any well in the Colony Granite Wash formation on acreage included within the AMI for its own account until it has satisfied its drilling obligation to the Trust.

The Royalty Interests entitle the Trust to receive 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sales of production of oil, NGL and natural gas attributable to Chesapeake's net revenue interest in the Producing Wells and 50% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sales of oil, NGL and natural gas production attributable to Chesapeake's net revenue interest in the Development Wells. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, NGL and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by Chesapeake or its affiliates.

On November 16, 2011, Chesapeake novated to the Trust, and the Trust became party to, derivative contracts covering a portion of the production attributable to the Royalty Interests from October 1, 2011 through September 30, 2015. The Trust's distributable income will include net settlements under these derivative contracts. The value of the derivative contracts as of December 31, 2013 and 2012 was a net liability of $8.1 million.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. During the year ended December 31, 2013, four distributions were paid. See Liquidity and Capital Resources below and Note 7 to the financial statements contained in Part II, Item 8 of this Annual Report for more information regarding the distributions.

The amount of Trust revenues and cash distributions to Trust unitholders will fluctuate from quarter to quarter depending on several factors, including:

- timing and amount of initial production and sales from the Development Wells;
- oil, NGL and natural gas prices received;
- volumes of oil, NGL and natural gas produced and sold;
- amounts received from, or paid under, derivative contracts;
- certain post-production expenses and any applicable taxes; and
- the Trust's expenses.

Results of Trust Operations

The quarterly payments to the Trust with respect to the Royalty Interests are based on the amount of proceeds actually received by Chesapeake during the preceding calendar quarter. Proceeds from production are typically received by Chesapeake one month after production. Due to the timing of the payment of production proceeds, quarterly distributions made by Chesapeake to the Trust will generally include royalties attributable to sales of oil, NGL and natural gas for three months, comprised of the first two months of the quarter just ended and the last month of the quarter prior to that one. Chesapeake is required to make the Royalty Interest payments to the Trust within 35 days of the end of each calendar quarter. During the year ended December 31, 2013, the Trust received payments on the Royalty Interests representing royalties attributable to proceeds from sales of oil, NGL and natural gas for September 1, 2012 through August 31, 2013. During the year ended December 31, 2012, the payments received by the Trust represented royalties attributable to proceeds from sales of oil, NGL and natural gas for September 1, 2011 through August 31, 2012. During the six months ended December 31, 2011, the payments received by the Trust represented royalties attributable to proceeds from sales of oil, NGL and natural gas for July 1, 2011 through August 31, 2011.

The Trust's income available for distribution to unitholders in 2013 and 2012 was adversely affected by several factors. Low natural gas prices combined with stronger oil prices have resulted in an industry-wide increase in drilling

activity in oil- and NGL-rich plays since 2010. The resulting increase in production volumes of NGL led to a significant decrease in the price of NGL in both absolute terms and on a relative basis compared to oil. In addition to the Trust's exposure to low prices for natural gas and NGL, the Trust experienced reduced production volumes in 2013, largely because of higher-than-expected pressure depletion within the AMI described below. For the quarterly production periods from July 2011 through February 2012, the Trust paid a common and subordinated unit distribution above the subordination threshold. For the quarterly production periods from March 2012 through May 2013, the Trust paid a common unit distribution at the subordination threshold and a subordinated unit distribution below the subordination threshold. For the quarterly production period from June 2013 through August 2013, the Trust paid a common unit distribution below the subordination threshold and no subordinated unit distribution was paid, and on February 7, 2014, the Trust announced that the quarterly common unit distribution for the production period from September 1, 2013 to November 30, 2013 that was paid on March 3, 2014 was below the subordination threshold and no subordinated unit distribution was paid. See Note 7 to the financial statements contained in Part II, Item 8 of this Annual Report for information regarding prior distributions paid and Note 8 to the financial statements contained in Part II, Item 8 of this Annual Report for information regarding the distribution paid on March 3, 2014 to record unitholders as of February 19, 2014. Low levels of future production will continue to reduce the Trust’s revenues and distributable income available to unitholders and likely result in continued distributions to common unitholders below the subordination threshold. When a quarterly cash distribution in respect of the common units is lower than the applicable subordination threshold, the common units will not be entitled to receive any additional distributions nor will the units be entitled to arrearages in any future quarter.

During the year ended December 31, 2013, the Trust recognized an aggregate of $50.7 million in impairments of the Royalty Interests primarily due to lower proved reserve quantities resulting from higher-than-expected pressure depletion within certain areas of the AMI. This pressure depletion has resulted in lower initial production rates and lower expected ultimate recovery in some recent Development Wells. See Note 2 to the financial statements contained in Part II, Item 8 of this Annual Report for further discussion of the impairments. In addition, during the year ended December 31, 2013, Chesapeake informed the Trust that it is performing additional testing and scientific analysis of the Colony Granite Wash reservoir in an effort to potentially enhance the value of the remaining Development Wells by optimizing well spacing and interval selections. Chesapeake reduced its operated rig count in the AMI from four rigs to two rigs in August 2013, which allows more time to apply well performance analysis from well to well as Chesapeake's drilling program progresses at a slower pace.

At this time, Chesapeake is unable to predict how long its operated rig count will remain at two rigs or the outcome of its additional testing and analysis, including any potential improvement in Development Well drilling performance or the potential effects on future distributions to common unitholders. The operated rig count reduction will decrease the rate at which royalty income from the remaining Development Wells becomes available to the Trust for distribution to unitholders, and if well performance does not improve, the Trust's revenues and distributable income available to unitholders will be reduced further, contributing to continued distributions to common unitholders below the subordination threshold. Decreased well performance or lower expected ultimate recovery may also lead to further impairments of the Royalty Interests.

Distributable Income. The Trust's distributable income was $104.9 million for the year ended December 31, 2013. This compares to $116.5 million for the year ended December 31, 2012. The decrease from 2012 to 2013 was primarily due to the decrease in the average realized prices received from sales of oil and NGL and lower than expected initial production rates from Development Wells completed in the production period from September 1, 2012 to August 31, 2013 ("2013 production period") as compared to the production period from September 1, 2011 to August 31, 2012 ("2012 production period"). These decreases were partially offset by an increase in the price received for natural gas for the 2013 production period compared to the 2012 production period. Distributable income paid to the Trust unitholders during the six months ended December 31, 2011 and attributable to production from July 1, 2011 to August 31, 2011 ("2011 production period") was $27.1 million, which included a $1.3 million reduction for Trust administrative expenses and a cash reserve for the payment of future Trust administrative expenses. The $89.4 million increase in the Trust's distributable income for the 2012 production period as compared to the 2011 production period was a result of a full twelve months of activity in the 2012 production period compared to two months in the 2011 production period. See Royalty Income below for information regarding average prices received and sales volumes. On a per unit basis, cash distributions during the year ended December 31, 2013 and attributable to the 2013 production period were $2.7171 per common unit and $0.8214 per subordinated unit compared to $2.6265 per common unit and $2.0892 per subordinated unit for the year ended December 31, 2012 and attributable to the 2012 production period and $0.5800 per common and subordinated unit for the six months ended December 31, 2011 and attributable to the 2011 production period. Distributable income for the production periods described above was calculated as follows:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
	($ in thousands, except per unit data)		
Revenues:			
Royalty income[1]	$114,010	$127,335	$29,334
Interest income	—	3	2
Total revenues	114,010	127,338	29,336
Expenses:			
Production taxes	2,216	2,707	906
Trust administrative expenses[2]	1,439	1,732	1,315
Cash settlements on derivatives	5,487	6,389	—
Total expenses	9,142	10,828	2,221
Distributable income available to unitholders	$104,868	$116,510	$27,115
Distributable income per common unit (35,062,500 units issued and outstanding)	$2.7171	$2.6265	$0.5800
Distributable income per subordinated unit (11,687,500 units issued and outstanding)	$0.8214	$2.0892	$0.5800

(1) Net of certain post-production expenses.
(2) Includes cash reserves withheld (used).

Royalty Income. Royalty income to the Trust for the year ended December 31, 2013, and attributable to the 2013 production period, totaled $114.0 million based upon sales of production attributable to the Royalty Interests of 544 mbbls of oil, 1,202 mbbls of NGL and 11,495 mmcf of natural gas. Total production attributable to the Royalty Interests for the 2013 production period was 3,661 mboe. Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production taxes, during the 2013 production period were $90.04 per bbl, $31.77 per bbl and $2.34 per mcf, respectively.

Royalty income to the Trust for the year ended December 31, 2012, and attributable to the 2012 production period, totaled $127.3 million based upon sales of production attributable to the Royalty Interests of 673 mbbls of oil, 1,234 mbbls of NGL and 12,179 mmcf of natural gas. Total production attributable to the Royalty Interests for the 2012 production period was 3,937 mboe. Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production taxes, during the 2012 production period were $91.65 per bbl, $35.01 per bbl and $1.84 per mcf, respectively.

Royalty income to the Trust for the six months ended December 31, 2011, and attributable to the 2011 production period, totaled $29.3 million based upon sales of production attributable to the Royalty Interests of 133 mbbls of oil, 225 mbbls of NGL and 2,172 mmcf of natural gas. Total production attributable to the Royalty Interests for the 2011 production period was 720 mboe. Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production taxes, during the 2011 production period were $88.26 per bbl, $46.65 per bbl and $3.26 per mcf, respectively.

Production Taxes. Production taxes are calculated as a percentage of oil, NGL and natural gas revenues, net of any applicable tax credits. Production taxes for the year ended December 31, 2013 totaled $2.2 million, or $0.61 per boe, or approximately 2.0% of royalty income, as compared to production taxes of $2.7 million, or $0.69 per boe, or approximately 2.1% of royalty income for the year ended December 31, 2012 and $0.9 million, or $1.26 per boe, or approximately 3.1% of royalty income for the six months ended December 31, 2011. The decrease in production

49

taxes per boe from 2012 to 2013 and from 2011 to 2012 was due to an increase in the number of wells taxed at an incentive tax rate due to horizontal well qualification.

Trust Administrative Expenses. Trust administrative expenses, including cash reserves, for the year ended December 31, 2013 totaled $1.4 million as compared to $1.7 million for the year ended December 31, 2012 and $1.3 million for the six months ended December 31, 2011. Trust administrative expenses primarily consist of the administrative fees paid to the Trustees and Chesapeake and costs for accounting and legal services. Administrative expenses for 2011 included an additional $1.0 million to establish an initial cash reserve.

Cash Settlements on Derivatives. The Trust records gains or losses from the derivative contracts when proceeds are received or payments are made, respectively. Swaps covering the 2013 production period were settled, during the year ended December 31, 2013, with proceeds from royalty income for the 2013 production period. Total losses during the year ended December 31, 2013 were $5.5 million. Swaps covering the 2012 production period were settled, during the year ended December 31, 2012, with proceeds from royalty income for the 2012 production period. Total losses during the year ended December 31, 2012 were $6.4 million. There were no such cash settlements during the six months ended December 31, 2011.

Impairments of Royalty Interests. During the year ended December 31, 2013, the Trust recognized an aggregate of $50.7 million in impairments of the Royalty Interests. The impairments were the result of downward reserve revisions attributable to 2013 production being below expectations, primarily as a result of higher-than-expected pressure depletion within some areas of the AMI. This has resulted in lower initial production rates and lower expected ultimate recovery in certain recent development wells. The impairment resulted in a non-cash charge to the Trust corpus and did not affect the Trust's distributable income. There were no such impairments for the year ended December 31, 2012 or the six months ended December 31, 2011.

Liquidity and Capital Resources

The Trust’s principal sources of liquidity and capital are cash flows generated from the Royalty Interests, the loan commitment as described below and, during periods in which oil prices fall below the fixed price received on derivative contracts, the derivative contracts. The Trust’s primary uses of cash are distributions to Trust unitholders, including, if applicable, incentive distributions to Chesapeake, payments of production taxes, payments of Trust administrative expenses, including any reserves established by the Trustee for future liabilities and repayment of loans, payments for derivative contract settlements and payments of expense reimbursements to Chesapeake for out-of-pocket expenses it incurs on behalf of the Trust. Administrative expenses include payments to the Trustee and the Delaware Trustee as well as a quarterly fee of $50,000 to Chesapeake pursuant to an administrative services agreement. Each quarter, the Trustee determines the amount of funds available for distribution. Available funds are the excess cash, if any, received by the Trust from the sales of oil, NGL and natural gas production attributable to the Royalty Interests during the quarter, over the Trust’s expenses for the quarter and any cash reserve for the payment of liabilities of the Trust, subject in all cases to the subordination and incentive provisions described previously.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust’s administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. During the year ended December 31, 2013, four distributions were paid. The 2013 fourth quarter distribution of $0.6671 per common unit, consisting of proceeds attributable to production from June 1, 2013 through August 31, 2013, was made on November 29, 2013 to record unitholders as of November 19, 2013. There was no distribution for the subordinated units for the 2013 fourth quarter. The 2013 third quarter distribution of $0.6900 per common unit and $0.1432 per subordinated unit, consisting of proceeds attributable to production from March 1, 2013 to May 31, 2013, was made on August 29, 2013 to record unitholders as of August 19, 2013. The 2013 second quarter distribution of $0.6900 per common unit and $0.3010 per subordinated unit, consisting of proceeds attributable to production from December 1, 2012 through February 28, 2013, was made on May 31, 2013 to record unitholders as of May 21, 2013. The 2013 first quarter distribution of $0.6700 per common unit and $0.3772 per subordinated unit, consisting of proceeds attributable to production from September 1, 2012 through November 30, 2012, was made on March 1, 2013 to record unitholders as of February 19, 2013.

The following is a summary of distributable income, distributable income per common unit and distributable income per subordinated unit by quarter for the years ended December 31, 2013 and 2012 and the six months ended December 31, 2011 (in thousands except per unit amounts):

2013	Q1	Q2	Q3	Q4	Total
Distributable income	$27,900	$27,711	$25,867	$23,390	$104,868
Distributable income per common unit	$0.6700	$0.6900	$0.6900	$0.6671	$2.7171
Distributable income per subordinated unit	$0.3772	$0.3010	$0.1432	$—	$0.8214
2012	Q1	Q2	Q3	Q4	Total
Distributable income	$34,019	$30,801	$27,020	$24,670	$116,510
Distributable income per common unit	$0.7277	$0.6588	$0.6100	$0.6300	$2.6265
Distributable income per subordinated unit	$0.7277	$0.6588	$0.4819	$0.2208	$2.0892
2011			Q3	Q4	Total
Distributable income			$—	$27,115	$27,115
Distributable income per common unit			$—	$0.5800	$0.5800
Distributable income per subordinated unit			$—	$0.5800	$0.5800

On February 7, 2014, the Trust declared a cash distribution of $0.6624 per common unit, which was $0.0276 below the applicable subordination threshold of $0.6900, and no distribution was declared for the subordinated units. The common unit distribution consisted of proceeds attributable to production from September 1, 2013 to November 30, 2013. The distribution was paid on March 3, 2014 to record unitholders as of February 19, 2014. The Trust's quarterly income available for distribution was $0.4968 per unit, which was $0.1932 below the subordination threshold. See Note 8 to the financial statements contained in Part II, Item 8 of this Annual Report for additional information regarding the distribution paid on March 3, 2014 to record unitholders as of February 19, 2014.

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.

Pursuant to the Trust Agreement, if at any time the Trust’s cash on hand (including cash reserves) is not sufficient to pay the Trust’s ordinary course expenses as they become due, Chesapeake will loan 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 current liabilities arising in the ordinary course of the Trust’s business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans 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. There were no loans outstanding as of December 31, 2013 or 2012.

The Trust is not responsible for any costs related to the drilling of the Development Wells and Chesapeake granted to the Trust the Drilling Support Lien in order to secure the estimated amount of the drilling costs for the Trust’s interests in the Development Wells. As Chesapeake fulfills its drilling obligation over time, Development Wells that are completed or that are perforated for completion and then plugged and abandoned are 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 is proportionately reduced.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements. The Trust has not guaranteed the debt of any other party, nor does the Trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations other than the derivative contracts disclosed in the section “Quantitative and Qualitative Disclosures About Market Risk” in Item 7A of this Annual Report.

Contractual Obligations

As of December 31, 2013, the Trust had no obligations or commitments to make future contractual payments other than the Trustee administrative fee, administrative services fee, the collateral agent fee and the Delaware Trustee administrative fee payable to the Trustee, Chesapeake and Wells Fargo Bank, N.A., as collateral agent under the derivative contracts and the Delaware Trustee, respectively.

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Contractual Obligations:	($ in thousands)				
Trustee administrative fee	$3,063	$175	$350	$350	$2,188
Chesapeake administrative services fee	3,500	200	400	400	2,500
Wells Fargo collateral agent fee(1)	46	23	23	—	—
Delaware Trustee administrative fee	35	2	4	4	25
Total contractual obligations	$6,644	$400	$777	$754	$4,713

(1) Collateral agent fee extends only through September 30, 2015.

The Trust is obligated to make quarterly cash distribution of substantially all of its cash receipts, after deducting the Trust's expenses, approximately 60 days following the completion of each calendar quarter through, and including, the quarter ending June 30, 2031.

Critical Accounting Policies and Estimates

Basis of Accounting. Financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) as the Trust records revenues when received and expenses when paid and may also establish certain cash reserves for contingencies that would not be accrued in financial statements prepared in accordance with GAAP. This non-GAAP, comprehensive basis of accounting corresponds to the accounting principles permitted for royalty trusts by the Securities and Exchange Commission (“SEC”) as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts. The Trust's financial statements as of December 31, 2013 and 2012 have been prepared by the Trust in accordance with the accounting policies noted below.

Investment in Royalty Interests. The conveyance of the Royalty Interests to the Trust was accounted for as a transfer of properties between entities under common control and recorded at the historical cost of Chesapeake (“Investment in Royalty Interests”), which was based on an allocation of the historical net book value of Chesapeake's full cost pool according to the fair value of the Royalty Interests relative to the fair value of Chesapeake's proved reserves. The carrying value of the Trust's Investment in Royalty Interests will not necessarily be indicative of the fair value of such Royalty Interests.

This investment is amortized as a single cost center on a units-of-production basis over total proved reserves. Such amortization does not reduce distributable income, rather it is charged directly to the Trust corpus. Revisions to estimated future units-of-production are treated on a prospective basis beginning on the date significant revisions are known.

On a quarterly basis, the Trust evaluates the carrying value of the Investment in Royalty Interests under the full cost accounting method prescribed by the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, the carrying value of the Investment in Royalty Interests may not exceed an amount equal to the PV-10 for the

Trust's proved reserves. Any write-downs resulting from the ceiling test will be non-cash charges to the Trust corpus and will not affect distributable income.

Use of Estimates. The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets, liabilities and Trust corpus during the reporting period. Significant estimates that impact the Trust's financial statements include estimates of proved oil, NGL and natural gas reserves, which are used to compute the Trust's amortization of Investment in Royalty Interests and, as necessary, to evaluate potential impairment of Investment in Royalty Interests and determine the fair value of derivatives. Actual results could differ from those estimates.

Derivatives. To mitigate a portion of the exposure to adverse market changes of oil and NGL prices, the Trust is party to derivative contracts with its derivative counterparty. See Note 3 to the financial statements contained in Part II, Item 8 of this Annual Report for further discussion of the derivative contracts currently outstanding.

The Trust records gains or losses from the derivative contracts conveyed under the derivative contracts when proceeds are received or payments are made, respectively. Additionally, changes in the fair value of the derivative contracts are accounted for as an adjustment to Trust corpus and the fair value carried on the Statements of Assets, Liabilities and Trust Corpus.

Revenues and Expenses. Revenues received by the Trust are net of existing royalties and overriding royalties associated with Chesapeake's interests and are reduced by certain post-production expenses, production taxes and other allowable expenses, such as the Trust's administrative expenses, in order to determine distributable income. The Royalty Interests are not burdened by field and lease operating expenses.

ITEM 7A. Quantitative and Qualitative Disclosures about Market Risk

The discussion in this section provides information about derivative contracts between the Trust and the derivative counterparty effective October 1, 2011. The derivative contracts cover a portion of the expected production attributable to the Royalty Interests from the Producing Wells and the Development Wells through September 30, 2015. The derivative contracts are settled in cash and do not require the actual delivery of oil or NGL at settlement. The contracts are settled based upon NYMEX prices. Under the derivative contracts, the Trust receives payments directly from the counterparty and pays any amounts owed to the counterparty. The Trust does not have the ability to enter into any additional crude oil, NGL or natural gas derivative contracts, except in limited circumstances involving the restructuring of the existing oil derivatives contracts.

As of December 31, 2013, the Trust had the following crude oil derivative contracts:

	Fixed-Price Oil Swaps		
Production Quarter	Volume (mbbl)	Weighted Avg. Price (per bbl)	Fair Value ($ in thousands)
Q3 2013[(1)]	60.5	$87.96	$(743)
Q4 2013[(2)]	184.2	$87.99	(2,117)
Q1 2014	179.8	$88.08	(1,791)
Q2 2014	180.3	$88.21	(1,544)
Q3 2014	178.8	$88.34	(1,123)
Q4 2014	174.3	$88.45	(700)
Q1 2015	171.0	$88.59	(307)
Q2 2015	175.4	$88.76	12
Q3 2015	153.6	$88.90	242
Total	1,457.9	$88.38	$(8,071)

(1) Includes September 2013 production that was settled in February 2014.

(2) Includes October and November 2013 production that was settled in February 2014.

To the extent expected oil production falls below the hedged oil volume, the derivative contracts will also cover expected NGL production. Such estimated production of NGL is hedged with crude oil derivative contracts using a conversion ratio of one barrel of NGL to 49.2% of one barrel of oil. In 2012 and 2013, NGL prices decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the derivative contracts will not effectively mitigate the price risk of the Trust's NGL production.

The Trust's obligations to the counterparty under the derivative contracts are secured by liens on proved reserves attributable to the Trust's interest in the Underlying Properties. The value of the derivative contracts as of December 31, 2013 was a net liability of $8.1 million.

Oil, NGL and Natural Gas Price Risk. The Trust's primary asset and source of income is the Royalty Interests, which generally entitles the Trust to receive a portion of the net proceeds from the sales of oil, NGL and natural gas from the Underlying Properties. The Trust is significantly exposed to fluctuations in the prices received for oil, NGL and natural gas produced and sold. The derivative contracts described above are designed to mitigate a portion of the variability of the prices received for the Trust's share of oil production. The use of crude oil derivative contracts to partially mitigate the price risk of NGL production, to the extent oil production falls below the hedged oil volume, is subject to basis risk to the extent oil and NGL prices are not highly correlated.

Credit Risk. A portion of the Trust's liquidity is concentrated in the derivative contracts described above. The use of crude oil derivative contracts exposes the Trust to credit risk from the counterparty, which has an investment grade credit rating.

Credit Risk Associated With Chesapeake. Chesapeake's ability to perform its obligations to the Trust will depend on its future results of operations, financial condition and liquidity, which in turn will depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

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 was limited to approximately $67.1 million as of March 10, 2014 and will decease as the remaining Development Wells are drilled and completed.

Delays and expenses associated with a foreclosure could reduce distributions to the Trust unitholders 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 Royalty Interests in the Development Wells.

In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed 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 could also be unable to provide support to the Trust through loans and performance of its management duties.

ITEM 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Unitholders of Chesapeake Granite Wash Trust and The Bank of New York Mellon Trust Company, N.A, Trustee:

We have audited the accompanying statements of assets, liabilities and trust corpus of Chesapeake Granite Wash Trust (the "Trust") as of December 31, 2013 and 2012 and the related statements of distributable income and of changes in trust corpus for each of the two years in the period ended December 31, 2013 and for the six month period ended December 31, 2011. We also have audited the Trust's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trustee is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the Trustee's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Trust's internal control over financial reporting based on our audits (which was an integrated audit in 2013 and 2012).

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As described in Note 2, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than generally accepted accounting principles in the United States of America.

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

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Trust at December 31, 2013 and 2012, and the distributable income and changes in trust corpus for each of the two years in the period ended December 31, 2013 and for the six month period ended December 31, 2011, on the basis of accounting described in Note 2. Also in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework (1992) issued by COSO.

/s/ PricewaterhouseCoopers LLP
Tulsa, Oklahoma

March 13, 2014

CHESAPEAKE GRANITE WASH TRUST
STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31, 2013	2012
	($ in thousands)	
ASSETS:		
Cash and cash equivalents	$1,136	$1,159
Investment in royalty interests	487,793	487,793
Less: accumulated amortization	(170,641)	(59,331)
Net investment in royalty interests	317,152	428,462
Total assets	$318,288	$429,621
LIABILITIES AND TRUST CORPUS:		
Short-term derivative liability	$7,045	$3,276
Long-term derivative liability	1,026	4,808
Total liabilities	8,071	8,084
Trust corpus; 35,062,500 common units and 11,687,500 subordinated units authorized and outstanding	310,217	421,537
Total liabilities and Trust corpus	$318,288	$429,621

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

CHESAPEAKE GRANITE WASH TRUST
STATEMENTS OF DISTRIBUTABLE INCOME

	Year Ended December 31, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
	($ in thousands, except per unit data)		
REVENUES:			
Royalty income	$114,010	$127,335	$29,334
Interest income	—	3	2
Total revenues	114,010	127,338	29,336
EXPENSES:			
Production taxes	2,216	2,707	906
Trust administrative expenses	1,439	1,732	1,315
Cash settlements on derivatives	5,487	6,389	—
Total expenses	9,142	10,828	2,221
Distributable income	$104,868	$116,510	$27,115
Distributable income per common unit (35,062,500 units)	$2.7171	$2.6265	$0.5800
Distributable income per subordinated unit (11,687,500 units)	$0.8214	$2.0892	$0.5800

CHESAPEAKE GRANITE WASH TRUST
STATEMENTS OF CHANGES IN TRUST CORPUS

	Year Ended December 31, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
	($ in thousands)		
TRUST CORPUS: Beginning of period	$421,537	$462,918	$1
Issuance of trust units, net of issuance costs of $27,312	—	—	409,688
Cash reserve surplus (deficit)	(22)	143	1,015
Conveyance of royalty interests	—	—	487,793
Consideration for investment in royalty interests	—	—	(409,688)
Amortization of investment in royalty interests	(60,577)	(53,981)	(5,350)
Impairment of investment in royalty interests	(50,734)	—	—
Derivative liability novation	—	—	(20,993)
Change in derivative liability	13	12,457	452
Distributable income	104,868	116,510	27,115
Distributions paid to unitholders	(104,868)	(116,510)	(27,115)
TRUST CORPUS: End of period	$310,217	$421,537	$462,918

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

57

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS

1. Organization of the Trust

Chesapeake Granite Wash Trust (the “Trust”) is a statutory trust formed in June 2011 under the Delaware Statutory Trust Act pursuant to an initial trust agreement by and among Chesapeake Energy Corporation ("Chesapeake"), as Trustor, The Bank of New York Mellon Trust Company, N.A., as Trustee (the “Trustee”), and The Corporation Trust Company, as Delaware Trustee (the “Delaware Trustee”).

The Trust was created to own royalty interests (the “Royalty Interests”) for the benefit of Trust unitholders pursuant to a trust agreement dated as of June 29, 2011 and subsequently amended and restated as of November 16, 2011 by and among Chesapeake, Chesapeake Exploration, L.L.C., a wholly owned subsidiary of Chesapeake, the Trustee and the Delaware Trustee (the “Trust Agreement”). The Royalty Interests are derived from Chesapeake’s interests in specified oil and natural gas properties located within an area of mutual interest (the "AMI") in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma (the “Underlying Properties”). Chesapeake conveyed the Royalty Interests to the Trust from (a) Chesapeake’s interests in 69 existing horizontal wells (the “Producing Wells”), and (b) Chesapeake’s interests in 118 horizontal development wells (the “Development Wells”) that have since been, or that are to be, drilled on properties held by Chesapeake within the AMI. Pursuant to a development agreement with the Trust, Chesapeake is obligated to drill, cause to be drilled or participate as a non-operator in the drilling of the 118 Development Wells by June 30, 2016. Additionally, based on Chesapeake’s assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake has retained an interest in each of the Producing Wells and Development Wells and currently operates 95% of the Producing Wells and the completed Development Wells and expects to operate 100% of the remaining Development Wells.

The business and affairs of the Trust are managed by the Trustee. The Trust Agreement limits the Trust’s business activities generally to owning the Royalty Interests and any activity reasonably related to such ownership, including activities required or permitted by the terms of the conveyances related to the Royalty Interests and derivative contracts between the Trust and its counterparty. The royalty interests in the Producing Wells entitle the Trust to receive 90% of the proceeds (exclusive of any production or development costs but after deducting certain post-production expenses and any applicable taxes) from the sales of oil, NGL and natural gas production attributable to Chesapeake’s net revenue interest in the Producing Wells. The royalty interests in the Development Wells entitle the Trust to receive 50% of the proceeds (exclusive of any production or development costs but after deducting certain post-production expenses and any applicable taxes) from the sales of oil, NGL and natural gas production attributable to Chesapeake’s net revenue interest in the Development Wells.

Through an initial public offering in November 2011, the Trust sold to the public 23,000,000 common units, representing beneficial interests in the Trust, for cash proceeds of approximately $409.7 million, net of offering costs. The Trust delivered the net proceeds of the initial public offering, along with 12,062,500 common units and 11,687,500 subordinated units, to certain wholly owned subsidiaries of Chesapeake in exchange for the conveyance of the Royalty Interests to the Trust. Upon completion of these transactions, there were 46,750,000 Trust units issued and outstanding, consisting of 35,062,500 common units and 11,687,500 subordinated units. The common units and subordinated units have identical rights and privileges, except with respect to their voting rights and rights to receive distributions as described below.

The subordinated units are 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 80% of the target distribution for the corresponding quarter (the “subordination threshold”). If there is not sufficient cash to fund such a distribution on all of the Trust 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 the common units. In exchange for agreeing to subordinate a portion of its Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake is 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 (the "incentive threshold"). The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. 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

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS – (Continued)

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.

The aggregate distributions paid in the year ended December 31, 2013 were $2.7171 per common unit and $0.8214 per subordinated unit. The distributable income for the four production periods from September 1, 2012 to August 31, 2013 was, in each case, below the subordination threshold. See Note 7 for additional information related to the quarterly cash distributions and Risks and Uncertainties in Note 2 below.

The Trust will dissolve and begin to liquidate on June 30, 2031, or earlier upon certain events (the "Termination Date"), and will soon thereafter wind up its affairs and terminate. At the Termination Date, (a) 50% of the total Royalty Interests conveyed by Chesapeake will revert automatically to Chesapeake and (b) 50% of the total Royalty Interests conveyed by Chesapeake (the "Perpetual Royalties") will be retained by the Trust and thereafter sold. The net proceeds of the sale of the Perpetual Royalties, as well as any remaining Trust cash reserves, will be distributed to the unitholders on a pro rata basis. Chesapeake will have a right of first refusal to purchase the Perpetual Royalties retained by the Trust at the Termination Date.

2. Basis of Presentation and Significant Accounting Policies

Basis of Accounting. Financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") as the Trust records revenues when received and expenses when paid and may also establish certain cash reserves for contingencies which would not be accrued in financial statements prepared in accordance with GAAP. This non-GAAP comprehensive basis of accounting corresponds to the accounting principles permitted for royalty trusts by the SEC as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

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

Use of Estimates. The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets, liabilities and Trust corpus during the reporting period. Significant estimates that impact the Trust's financial statements include estimates of proved oil and natural gas reserves, which are used to compute the Trust's amortization of the Investment in Royalty Interests (as defined in Investment in Royalty Interests below) and, as necessary, to evaluate potential impairments of Investment in Royalty Interests and determine the fair value of derivatives. Actual results could differ from those estimates.

Risks and Uncertainties. The Trust's revenue and distributions are substantially dependent upon the prevailing and future prices for oil, NGL and natural gas, each of which depends on numerous factors beyond the Trust's control such as economic conditions, regulatory developments and competition from other energy sources. Oil, NGL and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. The Trust's derivative contracts serve to mitigate the effect of this price volatility on a portion of the Trust's anticipated oil and NGL production through September 30, 2015. See Note 3 for the Trust's derivative contracts.

The Trust's income available for distribution in 2013 and 2012 was adversely affected by several factors. Low natural gas prices combined with stronger oil prices have resulted in an industry-wide increase in drilling activity in oil- and NGL-rich plays since 2010. The resulting increase in production volumes of NGL led to a significant decrease in the price of NGL in both absolute terms and on a relative basis compared to oil. In addition to the Trust's exposure to low prices for natural gas and NGL, the Trust experienced reduced production volumes in 2013, largely because of higher-than-expected pressure depletion within the AMI described below. For the quarterly production periods from July 2011 through February 2012, the Trust paid a common and subordinated unit distribution above the subordination threshold. For the quarterly production periods from March 2012 through May 2013, the Trust paid a common unit distribution at the subordination threshold and a subordinated unit distribution below the subordination threshold. For the quarterly production period from June 2013 through August 2013, the Trust paid a common unit distribution below the subordination threshold and no subordinated unit distribution was paid, and on February 7, 2014, the Trust announced that the quarterly common unit distribution for the production period from September 1, 2013 to November 30, 2013 that was paid on March 3, 2014 was below the subordination threshold and no subordinated unit distribution was paid. See Note 7 for information regarding prior distributions paid and Note 8 for information regarding the

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS – (Continued)

distribution paid on March 3, 2014 to record unitholders as of February 19, 2014. Low levels of future production will continue to reduce the Trust's revenues and distributable income available to unitholders and likely result in continued distributions to common unitholders below the subordination threshold. When a quarterly cash distribution in respect of the common units is lower than the applicable subordination threshold, the common units will not be entitled to receive any additional distributions nor will the units be entitled to arrearages in any future quarter.

During the year ended December 31, 2013, the Trust recognized an aggregate of $50.7 million in impairments of the Royalty Interests primarily due to lower proved reserve quantities resulting from higher-than-expected pressure depletion within certain areas of the AMI. This depletion has resulted in lower initial production rates and lower expected ultimate recovery in some recent Development Wells. See Investment in Royalty Interests below for further discussion of the impairments. In addition, during the year ended December 31, 2013, Chesapeake informed the Trust that it is performing additional testing and scientific analysis of the Colony Granite Wash reservoir in an effort to potentially enhance the value of the remaining Development Wells by optimizing well spacing and interval selections. Chesapeake reduced its operated rig count in the AMI from four rigs to two rigs in August 2013, which allows more time to apply well performance analysis from well to well as Chesapeake's drilling program progresses at a slower pace.

At this time, Chesapeake is unable to predict how long its operated rig count will remain at two rigs or the outcome of its additional testing and analysis, including any potential improvement in Development Well drilling performance or the potential effects on future distributions to common unitholders. The operated rig count reduction will decrease the rate at which royalty income from the remaining Development Wells becomes available to the Trust for distribution to unitholders, and if well performance does not improve, the Trust's revenues and distributable income available to unitholders will be reduced further, contributing to continued distributions to common unitholders below the subordination threshold. Decreased well performance or lower expected ultimate recovery may also lead to further impairments of the Royalty Interests.

Chesapeake's ability to perform its obligations to the Trust will depend on its future results of operations, financial condition and liquidity, which in turn will depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

If Chesapeake were to default on its obligation to drill the Development Wells, the Trust would be able to foreclose on a drilling support lien (the "Drilling Support Lien") to the extent of Chesapeake's remaining interests in the undeveloped portions of the AMI, file a lawsuit to collect monetary 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 was limited to approximately $79.4 million as of December 31, 2013 and further reduced to $67.1 million as of March 10, 2014. The maximum amount that may be recovered under the Drilling Support Lien will decrease as the remaining Development Wells are drilled and completed.

Delays and expenses associated with a foreclosure could reduce distributions to the Trust unitholders 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 Royalty Interests in the Development Wells.

In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed 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 could also be unable to provide support to the Trust through loans and performance of its management duties.

Cash. Cash equivalents include all highly-liquid instruments with maturities of three months or less at the time of acquisition. The Trustee maintains a minimum cash reserve of $1.0 million and may at the Trustee’s discretion reserve funds for future expected administrative expenses.

Investment in Royalty Interests. The Investment in Royalty Interests is amortized as a single cost center on a units-of-production basis over total proved reserves. Such amortization does not reduce distributable income, rather it is charged directly to Trust corpus. Revisions to estimated future units-of-production are treated on a prospective basis beginning on the date such revisions are known. The carrying value of the Trust’s Investment in Royalty Interests

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS – (Continued)

will not necessarily be indicative of the fair value of such Royalty Interests. The Trust is not burdened by development costs of the Royalty Interests.

On a quarterly basis, the Trust evaluates the carrying value of the Investment in Royalty Interests under the full cost accounting method prescribed by the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, the carrying value of the Investment in Royalty Interests may not exceed an amount equal to the sum of the present value (using a 10% discount rate) of the estimated future net revenues from proved reserves. For each of the first two quarters and the last quarter of 2013, the carrying value of the Investment in Royalty Interests exceeded the estimated present value calculation of future net revenues from proved reserves, resulting in an aggregate of $50.7 million in impairments in the carrying value of the Investment in Royalty Interests. There was no impairment recognized during the third quarter in 2013. The impairments were primarily the result of negative reserve revisions attributable to current results being below expectations, primarily caused by higher-than-expected pressure depletion within certain areas of the AMI which has resulted in lower initial production rates and lower expected ultimate recovery in some recent Development Wells. The impairments resulted in non-cash charges to Trust corpus and did not affect the Trust's distributable income. There were no such impairments during the year ended December 31, 2012 or the six months ended December 31, 2011. See Risks and Uncertainties above for further discussion.

Derivatives. To mitigate a portion of the exposure to adverse market changes of oil prices and, to the extent oil production falls below the hedged oil volume, NGL prices, the Trust is party to derivative contracts with its derivative counterparty. See Note 3 for discussion of the derivative contracts currently outstanding.

The Trust records gains or losses from the derivative contracts when proceeds are received or payments are made, respectively. Additionally, changes in the fair value of the derivative contracts are accounted for as an adjustment to Trust corpus and the fair value carried on the Statements of Assets, Liabilities and Trust Corpus. Cash distributions to unitholders will be increased or decreased by settlements of the Trust's derivative contracts.

Loan Commitment. Pursuant to the Trust Agreement, if at any time the Trust's cash on hand (including available cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will loan funds to the Trust necessary to pay such expenses. Such loans will be recorded as a liability on the Statements of Assets, Liabilities and Trust Corpus until repaid. A loan neither increases nor decreases distributions to unitholders; however, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until the loan is repaid. There were no loans outstanding as of December 31, 2013 or December 31, 2012.

Revenues and Expenses. Neither the Trust nor the Trustee is responsible for, or has any control over, any costs related to the drilling of the Development Wells or any other operating or capital costs of the Underlying Properties. The Trust's revenues with respect to the Royalty Interests in the Underlying Properties are net of existing royalties and overriding royalties associated with Chesapeake's interests and are determined after deducting certain post-production expenses and any applicable taxes associated with the Royalty Interests. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, NGL and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by affiliates of Chesapeake. Cash distributions to unitholders will be reduced by the Trust's general and administrative expenses and cash settlements on derivatives.

3. Derivative Contracts

The Trust uses derivative contracts in an effort to manage its exposure to variability in cash flow from changes in oil prices and, to the extent oil production falls below hedged oil volume, NGL prices. On November 16, 2011, Chesapeake novated the derivative contracts described in the table below to the Trust pursuant to which the Trust became party to derivative contracts covering a portion of its expected production from October 1, 2011 through September 30, 2015. These derivative contracts consist of fixed-price oil swaps, in which the Trust receives a fixed price and pays a floating market price based on New York Mercantile Exchange ("NYMEX") settlement prices, to the counterparty for the underlying commodity of the derivative. As a party to these contracts, the Trust receives payments directly from its counterparty or is required to pay any amounts owed directly to the counterparty. All swaps are net settled based on the difference between the fixed-price payment and the floating-price payment. Settlements are due on a quarterly basis, including the first two months of the calendar quarter just ended and the last month of the calendar quarter prior to that one. Any payment due to or from such counterparty will be made by the 40th day following the end of the calendar quarter in which such payments become due.

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS – (Continued)

The Trust’s obligations to the counterparty under the derivative contracts are secured by liens on proved reserves attributable to the Trust’s interest in the Underlying Properties. The counterparty’s obligations under the hedge facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts owed to the Trust exceed defined thresholds. Mark-to-market amounts did not exceed the defined thresholds as of December 31, 2013.

As of December 31, 2013, the Trust had the following crude oil derivative contracts:

Production Quarter	Fixed-Price Oil Swaps Volume (mbbl)	Weighted Avg. Price (per bbl)	Fair Value ($ in thousands)
Q3 2013[1]	60.5	$87.96	$(743)
Q4 2013[2]	184.2	$87.99	(2,117)
Q1 2014	179.8	$88.08	(1,791)
Q2 2014	180.3	$88.21	(1,544)
Q3 2014	178.8	$88.34	(1,123)
Q4 2014	174.3	$88.45	(700)
Q1 2015	171.0	$88.59	(307)
Q2 2015	175.4	$88.76	12
Q3 2015	153.6	$88.90	242
Total	1,457.9	$88.38	$(8,071)

(1) Includes September 2013 production that was settled in February 2014.

(2) Includes October and November 2013 production that was settled in February 2014.

To the extent expected oil production falls below the hedged oil volume, the derivative contracts will also cover expected NGL production. Such estimated production of NGL is hedged with crude oil derivative contracts using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. In 2012 and 2013, NGL prices decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the derivative contracts will not effectively mitigate the price risk of the Trust’s NGL production.

Additional Disclosures Regarding Derivative Contracts

In accordance with accounting guidance for derivatives and hedging, and because a legal right of set-off exists, the Trust has netted the value of its derivative contracts with the counterparty in the accompanying Statements of Assets, Liabilities and Trust Corpus. Short-term derivative liability represents the estimated fair value of derivatives scheduled to settle in cash over the next twelve months based on market prices as of December 31, 2013. The Trust does not apply hedge accounting to any of its derivative contracts, and therefore, any changes in the fair value of the derivative contracts prior to settlement are accounted for as an adjustment to Trust corpus. Results of settled derivative contracts are reflected in distributable income in the period when they are cash settled. For the years ended December 31, 2013 and 2012, the Trust settled derivative contracts that resulted in payments to the counterparty of $5.5 million and $6.4 million, respectively.

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS – (Continued)

The following table presents the fair value and location of each classification of derivative contracts disclosed in the Statements of Assets, Liabilities and Trust Corpus as of December 31, 2013 and 2012 on a gross basis without regard to same-counterparty netting:

	Statements of Assets, Liabilities and Trust Corpus Location	Fair Value December 31, 2013	December 31, 2012
		($ in thousands)	
Asset Derivatives:			
Not designated as hedging instrument			
Commodity contracts	Short-term derivative asset	$—	$212
Commodity contracts	Long-term derivative asset	728	411
Total		728	623
Liability Derivatives:			
Not designated as hedging instrument			
Commodity contracts	Short-term derivative liability	(7,045)	(3,488)
Commodity contracts	Long-term derivative liability	(1,754)	(5,219)
Total		(8,799)	(8,707)
Total derivatives instruments		$(8,071)	$(8,084)

All of the Trust's derivative positions are subject to netting arrangements which provide for offsetting of asset and liability positions, as well as related cash collateral if applicable. Such netting arrangements generally do not have restrictions. Under such netting arrangements, the Trust offsets the fair value of derivative instruments with cash collateral received or paid for those contracts executed with the same counterparty, which reduces the Trust's total assets and Trust corpus. As of December 31, 2013 and 2012, the Trust did not have any cash collateral balances for these derivatives.

The following tables present the netting offsets of derivative assets and liabilities as of December 31, 2013 and 2012:

	December 31, 2013			
	Derivative Assets		Derivative Liabilities	
	Short-term	Long-term	Short-term	Long-term
	($ in thousands)			
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	$—	$728	$(7,045)	$(1,754)
Gross amounts offset in the statements of assets, liabilities and trust corpus	—	(728)	—	728
Total derivatives as reported	$—	$—	$(7,045)	$(1,026)

	December 31, 2012			
	Derivative Assets		Derivative Liabilities	
	Short-term	Long-term	Short-term	Long-term
	($ in thousands)			
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	$212	$411	$(3,488)	$(5,219)
Gross amounts offset in the statements of assets, liabilities and trust corpus	(212)	(411)	212	411
Total derivatives as reported	$—	$—	$(3,276)	$(4,808)

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS – (Continued)

4. Income Taxes

The Trust is a Delaware statutory trust that is treated as a partnership for U.S. federal income tax purposes. The Trust is not required to pay federal or state income taxes. Accordingly, no provision for federal or state income tax has been made.

Trust unitholders are 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, deductions and credits 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.

5. Related Party Transactions

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of \$175,000 to the Trustee, paid in equal quarterly installments. The administrative fee may be adjusted for inflation by no more than 3% in any calendar year beginning in 2015. The Trustee did not receive a fee for the six months ended December 31, 2011.

Agreements with Chesapeake. In connection with the initial public offering and the conveyance of the Royalty Interests to the Trust, the Trust entered into an administrative service agreement, a development agreement and a registration rights agreement with Chesapeake.

Pursuant to the administrative services agreement, Chesapeake provides the Trust with certain accounting, tax preparation, bookkeeping and information services related to the Royalty Interests and the registration rights agreement. In return for the services provided by Chesapeake under the administrative services agreement, the Trust pays Chesapeake, in equal quarterly installments, an annual fee of \$200,000, which will remain fixed for the life of the Trust. Chesapeake is also 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. Chesapeake was paid approximately \$317,000, \$306,000 and \$106,000 in fees and reimbursements in 2013, 2012 and 2011, respectively.

Additionally, the administrative services agreement established Chesapeake as the Trust's hedge manager, pursuant to which Chesapeake has the authority, on behalf of the Trust, to administer the Trust's derivative contracts. As hedge manager, Chesapeake also has authority to terminate, restructure or otherwise modify all or any portion of the derivative contracts to the extent that Chesapeake reasonably determines, acting in good faith, that the volumes hedged under such contracts exceed, or are expected to exceed, the combined estimated production attributable to the Royalty Interests over the periods hedged. However, in fulfilling its role as hedge manager, Chesapeake does not act as a fiduciary for the Trust and has no affirmative duty to modify any of the Trust's derivative contracts, except as required by the derivative contracts and the administrative services agreement. Moreover, the Trust will indemnify Chesapeake for any actions it takes in this regard.

The administrative services agreement will terminate upon the earliest to occur of (a) the date the Trust shall have dissolved and wound up its business and affairs 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.

The development agreement obligates Chesapeake to drill, cause to be drilled or participate as a non-operator in the drilling of the Development Wells on or prior to June 30, 2016. Additionally, based on Chesapeake's assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake has also agreed not to drill and complete, or permit any other person within its control to drill and complete, any well in the AMI other than the Development Wells until Chesapeake has met its obligation to drill the Development Wells.

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 (the “Reasonably Prudent Operator Standard”). Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS – (Continued)

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, the existing Development Wells and other Colony Granite Wash producing wells outside of the AMI.

Under the development agreement, 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 receives proportionate credit.

A wholly owned subsidiary of Chesapeake has granted to the Trust the Drilling Support Lien covering Chesapeake's retained interest in the AMI (except its interest in the Producing Wells, Development Wells and any other wells 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 the Trust pursuant to the Drilling Support Lien initially could not exceed $262.7 million. As Chesapeake fulfills its drilling obligation over time, the total amount that may be recovered is proportionately reduced and completed Development Wells are released from the lien. If Chesapeake does not fulfill its drilling obligation by June 30, 2016, the Trust may foreclose on any remaining interest in the AMI that is subject to the Drilling Support Lien. Any amounts actually recovered in a foreclosure action would be applied to the completion of Chesapeake's drilling obligation and would not result in any distribution to the Trust unitholders.

Chesapeake's drilling activity with respect to the Development Wells is consistent with its intent to meet the drilling obligation contemplated by the development agreement. As of March 10, 2014, Chesapeake had drilled and completed, or caused to be drilled or completed, a total of 79 wells in the AMI (approximately 87.9 Development Wells as calculated under the development agreement), reducing the amount that may be recovered under the Drilling Support Lien to approximately $67.1 million. See Risks and Uncertainties in Note 2 regarding the operated rig count reduction from four rigs to two rigs in connection with testing and analysis that Chesapeake is conducting related to future Development Well drilling.

The Trust also entered into a registration rights agreement for the benefit of Chesapeake and certain of its affiliates (each, a "holder"). Pursuant to the registration rights agreement, the Trust agreed to register the Trust units held by each such holder for resale under the Securities Act of 1933, as amended. 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.

Loan Commitment. Pursuant to the Trust Agreement, if at any time the Trust's cash on hand (including available cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will loan 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 current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans 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. There were no loans outstanding as of December 31, 2013 or 2012.

6. Fair Value Measurement

Certain financial instruments are reported at fair value on the Statements of Assets, Liabilities and Trust Corpus. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. The Trust uses a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS – (Continued)

Derivatives. The fair value of the Trust's derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by our counterparty for reasonableness. Since commodity swaps do not include optionality and therefore have no unobservable inputs, they are classified as Level 2.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2013:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in thousands)			
Financial Assets (Liabilities):				
Derivative liabilities	$—	$(8,071)	$—	$(8,071)
Total	$—	$(8,071)	$—	$(8,071)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2012:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in thousands)			
Financial Assets (Liabilities):				
Derivative liabilities	$—	$(8,084)	$—	$(8,084)
Total	$—	$(8,084)	$—	$(8,084)

Fair Value of Other Financial Instruments. The estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. The carrying values of financial instruments comprising cash and cash equivalents approximate fair values due to the short-term maturities of these instruments.

7. Distributions to Unitholders

The Trust makes 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.

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS – (Continued)

For the years ended December 31, 2013 and 2012 and the six months ended December 31, 2011, the Trust declared and paid the following cash distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
June 2013 - August 2013	November 29, 2013	$0.6671	$—
March 2013 - May 2013	August 29, 2013	$0.6900	$0.1432
December 2012 - February 2013	May 31, 2013	$0.6900	$0.3010
September 2012 - November 2012	March 1, 2013	$0.6700	$0.3772
June 2012 - August 2012	November 29, 2012	$0.6300	$0.2208
March 2012 - May 2012	August 30, 2012	$0.6100	$0.4819
December 2011 - February 2012	May 31, 2012	$0.6588	$0.6588
September 2011 - November 2011	March 1, 2012	$0.7277	$0.7277
July 2011 - August 2011	December 28, 2011	$0.5800	$0.5800

8. Subsequent Events

On February 7, 2014, the Trust declared a cash distribution of $0.6624 per common unit consisting of proceeds attributable to production from September 1, 2013 to November 30, 2013, to record unitholders as of February 19, 2014. The distribution was paid on March 3, 2014. The Trust’s quarterly calculated income available for distribution was $0.4968 per unit, which was $0.1932 below the subordination threshold of $0.6900. For this distribution, all of the quarterly income available for distribution was used to make a distribution of $0.6624 per common unit, which was $.0276 below the applicable subordination threshold, and no distribution was paid to the subordinated units.
Distributable income attributable to production from September 1, 2013 to November 30, 2013 was calculated as follows (in thousands except for unit and per unit amounts):

Revenues:	
Royalty income[(1)]	$26,322
Total revenues	26,322
Expenses:	
Production taxes	513
Trust administrative expenses[(2)]	317
Derivative settlement loss	2,265
Total expenses	3,095
Distributable income available to unitholders	$23,227
Distributable income per common unit (35,062,500 units issued and outstanding)	$0.6624
Distributable income per subordinated unit (11,687,500 units issued and outstanding)[(3)]	$—

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(1) Net of certain post-production expenses.
(2) Includes cash reserves withheld (used).
(3) As the distribution per common unit was below the subordination threshold, no distribution was declared for the subordinated units.

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION

Quarterly Financial Data (unaudited)
The following is a summary of royalty income, interest income and distributable income by quarter for 2013 and 2012 (in thousands except per unit amounts):

	Year Ended December 31, 2013				
	Q1	Q2	Q3	Q4	2013
Royalty income	$29,463	$29,868	$27,759	$26,920	$114,010
Interest income	$—	$—	$—	$—	$—
Distributable income	$27,900	$27,711	$25,867	$23,390	$104,868
Distributable income per common unit	$0.6700	$0.6900	$0.6900	$0.6671	$2.7171
Distributable income per subordinated unit	$0.3772	$0.3010	$0.1432	$—	$0.8214
	Year Ended December 31, 2012				
	Q1	Q2	Q3	Q4	2012
Royalty income	$36,070	$34,554	$30,955	$25,756	$127,335
Interest income	$1	$1	$1	$—	$3
Distributable income	$34,019	$30,801	$27,020	$24,670	$116,510
Distributable income per common unit	$0.7277	$0.6588	$0.6100	$0.6300	$2.6265
Distributable income per subordinated unit	$0.7277	$0.6588	$0.4819	$0.2208	$2.0892

Supplemental Disclosures About Natural Gas, Oil and NGL Producing Activities (unaudited)
Net Capitalized Costs. Capitalized costs related to the Trust's oil, NGL and natural gas producing activities are summarized as follows:

	December 31,	
	2013	2012
	($ in thousands)	
Natural gas and oil properties:		
Proved	$487,793	$487,793
Unproved	—	—
Total	487,793	487,793
Less accumulated amortization	(170,641)	(59,331)
Net capitalized costs	$317,152	$428,462

The Royalty Interests conveyed to the Trust by Chesapeake consist of interests in proved properties only. The Trust capitalized approximately $487.8 million for the properties conveyed to the Trust concurrent with the initial public offering.
Costs Incurred in Oil and Natural Gas Drilling and Completion and Investment in Royalty Interest. Costs incurred in oil and natural gas drilling and completion, acquisition and divestiture activities which have been capitalized are limited to the $487.8 million of initial investment in proved properties at the inception of the Trust. The Trust will not acquire or dispose of properties and is not burdened with drilling and completion costs.

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION - (Continued)

Results of Operations from Oil, NGL and Natural Gas Producing Activities. Chesapeake's results of operations from oil and natural gas producing activities for the Trust's interest are presented below for the years ended December 31, 2013 and 2012 and the six months ended December 31, 2011. The following table includes revenues and expenses associated directly with the Trust's oil and natural gas producing activities. Production expenses and production taxes are deducted by Chesapeake prior to remittance of royalty income to the Trust. The following calculation does not include any interest income or general and administrative costs and, therefore, is not necessarily indicative of distributable income:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
	($ in thousands)		
Sales of oil, NGL and natural gas	$114,010	$127,335	$29,334
Production expenses[1]	—	—	—
Production taxes	(2,216)	(2,707)	(906)
Depletion and depreciation	(60,577)	(53,981)	(5,350)
Impairment of investment in royalty interests	(50,734)	—	—
Income tax provision[1]	—	—	—
Royalty income from oil, NGL and natural gas producing activities	$483	$70,647	$23,078

(1) The Trust does not bear any operating costs and is not subject to federal or state income taxes.

The following oil, NGL and natural gas information was prepared on an accrual basis, which is the basis upon which Chesapeake maintains its records and is different from the modified cash basis on which the Trust financial statements are prepared. A reconciliation of information presented on the modified cash basis to the accrual basis for the year ended December 31, 2013 is as follows:

Year ended December 31, 2013	Modified Cash Basis[1]	For the period September 1, 2012 to December 31, 2012	September 1, 2013 to December 31, 2013	Accrual Basis[2]
Production Data:				
Oil (mbbl)	544	(194)	146	496
NGL (mbbl)	1,202	(434)	359	1,127
Natural Gas (mmcf)	11,495	(4,010)	3,249	10,734
Total (mboe)	3,661	(1,297)	1,047	3,411
Royalty income (in thousands)	$114,010	$(39,154)	$34,356	$109,212
Production taxes (in thousands)	(2,216)	926	(666)	(1,956)
	$111,794	$(38,228)	$33,690	$107,256

(1) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses included in Chesapeake's 2013 net revenue distributions to the Trust. Represents oil and natural gas production from September 1, 2012 to August 31, 2013.

(2) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses, presented on an accrual basis, from January 1, 2013 through December 31, 2013, a portion of which will be reflected on the modified cash basis in distributable income in subsequent quarters.

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION - (Continued)

A reconciliation of information presented on the modified cash basis to the accrual basis for the year ended December 31, 2012 is as follows:

Year ended December 31, 2012	For the period Modified Cash Basis(1)	September 1, 2011 to December 31, 2011	September 1, 2012 to December 31, 2012	Accrual Basis(2)
Production Data:				
Oil (mbbl)	673	(218)	194	649
NGL (mbbl)	1,234	(384)	434	1,284
Natural Gas (mmcf)	12,179	(3,751)	4,010	12,438
Total (mboe)	3,937	(1,228)	1,297	4,006
Royalty income (in thousands)	$127,335	$(45,281)	$39,154	$121,208
Production taxes (in thousands)	(2,707)	1,004	(926)	(2,629)
	$124,628	$(44,277)	$38,228	$118,579

(1) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses included in Chesapeake's 2012 net revenue distributions to the Trust. Represents oil and natural gas production from September 1, 2011 to August 31, 2012.

(2) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses, presented on an accrual basis, from January 1, 2012 through December 31, 2012, a portion of which will be reflected on the modified cash basis in distributable income in subsequent quarters.

A reconciliation of information presented on the modified cash basis to the accrual basis for the six months ended December 31, 2011 is as follows:

Six months ended December 31, 2011	For the period Modified Cash Basis(1)	September 1, 2011 to December 31, 2011	Accrual Basis(2)
Production Data:			
Oil (mbbl)	133	218	351
NGL (mbbl)	225	384	609
Natural Gas (mmcf)	2,172	3,751	5,923
Total (mboe)	720	1,228	1,948
Royalty income (in thousands)	$29,334	$45,281	$74,615
Production taxes (in thousands)	(906)	(1,004)	(1,910)
	$28,428	$44,277	$72,705

(1) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses included in Chesapeake's 2011 net revenue distributions to the Trust. Represents oil and natural gas production from July 1, 2011 to August 31, 2011.

(2) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses, presented on an accrual basis, from July 1, 2011 through December 31, 2011, a portion of which will be reflected on the modified cash basis in distributable income in subsequent quarters.

Estimated Oil and Natural Gas Reserve Quantities. The Trust's independent petroleum engineering firm, Ryder Scott Company, L.P. (“Ryder Scott”), estimated all of the proved reserves as of December 31, 2013 for the Royalty

70

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION - (Continued)

Interest. The qualifications of the technical person at Ryder Scott Company, L.P. primarily responsible for overseeing his firm's preparation of the Trust's reserve estimates are set forth below.

- over 30 years of practical experience in the estimation and evaluation of reserves;
- registered professional engineer in the state of Texas;
- Bachelor of Science degree in Electrical Engineering; and
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Proved oil and natural gas reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from 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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is calculated using 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. 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 the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establish a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural 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: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Developed oil and natural gas reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

The information below on our oil and natural gas reserves attributed to the Royalty Interests is presented in accordance with regulations prescribed by the SEC in effect as of the date of such estimates. Our reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates will change as future information becomes available and as commodity prices change. Such changes could be material and could occur in the near term.

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION - (Continued)

Presented below is a summary of changes in estimated reserves of the Royalty Interests for 2013, 2012 and 2011.

	December 31, 2013			
	Oil (mbbl)	NGL (mbbl)	Gas (mmcf)	Total (mboe)
Beginning of period, accrual basis	3,573	9,201	92,572	28,203
Extensions, discoveries and other additions	277	530	6,481	1,887
Revisions of previous estimates, price	1	12	123	34
Revisions of previous estimates, other[1]	(1,253)	(2,367)	(27,096)	(8,137)
Production	(496)	(1,175)	(10,885)	(3,485)
Proved reserves, end of period	2,102	6,201	61,195	18,502
Proved developed reserves:				
Beginning of period	1,708	5,635	56,224	16,714
End of period	1,274	4,339	42,161	12,640
Proved undeveloped reserves:				
Beginning of period	1,865	3,566	36,348	11,489
End of period	828	1,862	19,034	5,862

	December 31, 2012			
	Oil (mbbl)	NGL (mbbl)	Gas (mmcf)	Total (mboe)
Beginning of period, accrual basis	5,928	13,661	135,567	42,184
Extensions, discoveries and other additions	234	471	5,018	1,541
Revisions of previous estimates, price[2]	(157)	(357)	(3,558)	(1,106)
Revisions of previous estimates, other[2]	(1,783)	(3,290)	(32,017)	(10,410)
Production	(649)	(1,284)	(12,438)	(4,006)
Proved reserves, end of period	3,573	9,201	92,572	28,203
Proved developed reserves:				
Beginning of period	2,076	6,021	58,724	17,884
End of period	1,708	5,635	56,224	16,714
Proved undeveloped reserves:				
Beginning of period	3,852	7,640	76,843	24,300
End of period	1,865	3,566	36,348	11,489

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION - (Continued)

	December 31, 2011			
	Oil (mbbl)	NGL (mbbl)	Gas (mmcf)	Total (mboe)
Beginning of period, accrual basis	6,235	14,554	140,861	44,266
Extensions, discoveries and other additions	—	—	—	—
Revisions of previous estimates, price	—	—	—	—
Revisions of previous estimates, other	44	(284)	629	(134)
Production	(351)	(609)	(5,923)	(1,948)
Proved reserves, end of period	5,928	13,661	135,567	42,184
Proved developed reserves:				
Beginning of period	2,233	6,235	60,536	18,557
End of period	2,076	6,021	58,724	17,884
Proved undeveloped reserves:				
Beginning of period	4,002	8,319	80,325	25,709
End of period	3,852	7,640	76,843	24,300

(1) During 2013, the Trust recorded downward reserve revisions of 8,137 mboe to the December 31, 2012 estimates of reserves resulting from changes to previous estimates. These non-price related revisions were primarily due to higher-than-expected pressure depletion in certain areas of the AMI and removal of reserves that are not part of Chesapeake's five year development plan within the AMI. Due to the higher-than-expected pressure depletion discussed above, Chesapeake reduced its operated rig count in the AMI from four rigs to two rigs in August 2013, which will allow more time to apply well performance analysis from well to well as Chesapeake's drilling program progresses at a slower pace.

(2) During 2012, the Trust recorded downward reserve revisions of 11,516 mboe to the December 31, 2011 estimates of reserves. Included in the revisions were 1,106 mboe of downward revisions resulting from lower natural gas prices in 2012 and 10,410 mboe of downward revisions resulting from changes to previous estimates. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The non-price related revisions were primarily due to current results being below expectations, primarily as a result of higher-than-expected pressure depletion within certain areas of the AMI.

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION - (Continued)

Presented below is a summary of the adjustment to the estimated reserves attributable to the Royalty Interests to adjust the reserves to the balance attributable to the Trust under the modified cash basis of accounting as of December 31, 2013, 2012 and 2011.

	December 31, 2013			
	Oil (mbbl)	NGL (mbbl)	Gas (mmcf)	Total (mboe)
Proved reserves, accrual basis	2,102	6,201	61,195	18,502
Production September 1 - December 31, 2013[(1)]	146	359	3,249	1,047
Adjusted Proved reserves, on a modified cash basis	2,248	6,560	64,444	19,549
	December 31, 2012			
	Oil (mbbl)	NGL (mbbl)	Gas (mmcf)	Total (mboe)
Proved reserves, accrual basis	3,573	9,201	92,572	28,203
Production September 1 - December 31, 2012[(2)]	194	434	4,010	1,297
Adjusted Proved reserves, on a modified cash basis	3,767	9,635	96,582	29,500
	December 31, 2011			
	Oil (mbbl)	NGL (mbbl)	Gas (mmcf)	Total (mboe)
Proved reserves, accrual basis	5,928	13,661	135,567	42,184
Production September 1 - December 31, 2012[(3)]	218	384	3,751	1,228
Adjusted Proved reserves, on a modified cash basis	6,146	14,045	139,318	43,412

(1) As of December 31, 2013 the Trust had not received royalty income associated with the production sold from September 1 - December 31, 2013. The reserves are adjusted to include such amount in proved reserves.

(2) As of December 31, 2012 the Trust had not received royalty income associated with the production sold from September 1 - December 31, 2012. The reserves are adjusted to include such amount in proved reserves.

(3) As of December 31, 2011 the Trust had not received royalty income associated with the production sold from September 1 - December 31, 2011. The reserves are adjusted to include such amount in proved reserves.

Standardized Measure of Discounted Future Net Cash Flows. Accounting Standards Topic 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has advised the Trustee that Chesapeake followed these guidelines, which are briefly discussed below.

Future cash inflows and future production costs as of December 31, 2013 were determined by applying the trailing average of the first-day-of-the-month prices for the 12 months of the year and year-end costs to the estimated quantities of oil and natural gas to be produced. Actual future prices and costs may be materially higher or lower than the 12-month average prices and year-end costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for such year. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computation since these estimates reflect the valuation process.

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION - (Continued)

The following summary sets forth our future net cash flows relating to proved oil and natural gas reserves based on the standardized measure:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
	($ in thousands)		
Future cash inflows	$536,450 (1)	$778,663 (2)	$1,546,856 (3)
Future production costs[4]	(26,228)	(37,510)	(74,035)
Future development costs[5]	—	—	—
Future income tax provisions[6]	—	—	—
Future net cash flows	510,222	741,153	1,472,821
Less effect of a 10% discount factor	(193,071)	(298,249)	(625,661)
Standardized measure of discounted future net cash flows	$317,151	$442,904	$847,160

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(1) Calculated using prices of $3.67 per mcf of natural gas and $96.82 per bbl of oil and NGL, before field differentials. Including the effect of price differential adjustments, the prices used in computing the reserves attributable to the Royalty Interests as of December 31, 2013 were $2.36 per mcf of natural gas, $92.35 per barrel of oil and $31.86 per barrel of NGL.

(2) Calculated using prices of $2.76 per mcf of natural gas and $94.84 per bbl of oil and NGL, before field differentials. Including the effect of price differential adjustments, the prices used in computing the reserves attributable to the Royalty Interests as of December 31, 2012 were $1.60 per mcf of natural gas, $90.89 per barrel of oil and $33.21 per barrel of NGL.

(3) Calculated using prices of $4.12 per mcf of natural gas and $95.97 per bbl of oil and NGL, before field differentials. Including the effect of price differential adjustments, the prices used in computing the reserves attributable to the Royalty Interests as of December 31, 2011 were $3.05 per mcf of natural gas, $91.65 per barrel of oil and $43.19 per barrel of NGL.

(4) Future production costs include the Trust's proportionate share of production taxes and post-production costs. The Trust does not bear any operational costs related to the wells.

(5) Future net cash flow has been calculated without deduction for future development costs as the Trust does not bear those costs.

(6) No provision for federal or state income taxes has been provided for in the calculation because taxable income is passed through to the unitholders of the Trust.

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION - (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following schedule reconciles the changes for the years ended December 31, 2013 and 2012 and the six months ended December 31, 2011 in the standardized measure of discounted future net cash flows relating to proved reserves:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
	($ in thousands)		
Standardized measure, beginning of period	$442,904	$847,160	$811,140
Sales of oil and gas produced, net of production costs	(108,914)	(118,579)	(72,705)
Net changes in prices and production costs	21,856	(164,294)	54,646
Extensions and discoveries, net of production and development costs	43,227	—	—
Revision of previous quantity estimates	(138,506)	(161,472)	(3,294)
Purchase of reserves-in-place	—	—	600
Accretion of discount	44,290	84,716	40,557
Other	12,294	(44,627)	16,216
Standardized measure, end of period	$317,151	$442,904	$847,160

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

None.

ITEM 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by several parties including, without limitation, Chesapeake and the independent reserve engineer to The Bank of New York Mellon Trust Company, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosures. As of the end of the period covered by this Annual Report, the Trustee carried out an evaluation of the Trustee's disclosure controls and procedures. Michael J. Ulrich, as Trust Officer of the Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the nature of the Trust as a passive entity and in light of the contractual arrangements pursuant to which the Trust was created, including the provisions of (i) the Trust Agreement, (ii) the administrative services agreement, (iii) the development agreement and (iv) the conveyances granting the Royalty Interests, the Trustee's disclosure controls and procedures related to the Trust necessarily rely on (a) information provided by Chesapeake, including information relating to results of operations, the status of drilling of the Development Wells, the costs and revenues attributable to the Trust's interests under the conveyance and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the underlying properties and the Royalty Interests, and (b) conclusions and reports regarding reserves by the Trust's independent reserve engineers. Other than reviewing the financial and other information provided to the Trust by Chesapeake and the independent reserve engineer, the Trustee made no independent or direct verification of this financial or other information.

Changes in Internal Control over Financial Reporting. During the year ended December 31, 2013, there has been no change in the Trustee's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trustee's internal control over financial reporting related to the Trust. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of Chesapeake.

Trustee's Report on Internal Control Over Financial Reporting. The Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f), by the Trust. The Trust's internal control over financial reporting is a process designed under the supervision of the Trustee to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Trust's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2013, the Trustee assessed the effectiveness of the Trust's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control-Integrated Framework (1992)," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, the Trustee determined that the Trust maintained effective internal control over financial reporting as of December 31, 2013, based on those criteria.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the financial statements of the Trust included in this Annual Report, has also audited the effectiveness of the Trust's internal control over financial reporting as of December 31, 2013, as stated in their accompanying report included in Item 8.

ITEM 9B. Other Information

None.

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

The Trust has no directors or executive officers. The Trustee is a corporate trustee that may be removed by the affirmative vote of the holders of not less than a majority of the outstanding Trust units at a meeting at which a quorum is present.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires the holders of more than 10 percent of the Trust units to file with the SEC reports regarding their ownership and changes in ownership of the Trust units. The Trustee is not aware of any 10 percent unitholder having failed to comply with all Section 16(a) filing requirements in 2013. In making these statements, the Trustee has relied upon examination of the copies of documents, to the extent there were any, provided to the Trust.

Audit Committee and Nominating Committee

Because the Trust does not have a board of directors, it does not have an audit committee, an audit committee financial expert or a nominating committee.

Code of Ethics

The Trust does not have a principal executive officer, principal financial officer, principal accounting officer or controller and, therefore, has not adopted a code of ethics applicable to such persons. However, employees of the Trustee must comply with the Trustee's code of ethics.

ITEM 11. Executive Compensation

During the years ended December 31, 2013 and 2012, the Trustee received an administrative fee of $175,000 from the Trust. The Trustee did not receive a fee for the six months ended December 31, 2011. The Trust does not have any executive officers, directors or employees. Because the Trust does not have a board of directors, it does not have a compensation committee.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

(a) Security Ownership of Certain Beneficial Owners

Based on filings with the SEC, the Trustee is not aware of any holders of 5% or more of the units except as set forth below. The following information has been obtained from filings with the SEC on Schedule 13D.

Beneficial Owner	Trust Units Beneficially Owned	Percent of Class
Chesapeake Energy Corporation[(1)]	12,062,500 Common Units	34.4%
Chesapeake Energy Corporation[(1)]	11,687,500 Subordinated Units	100%

(1) Chesapeake Energy Corporation, located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118, is the ultimate parent company of Chesapeake Exploration, L.L.C., which is the owner of the common units and subordinated units reported in the table above. Chesapeake may be deemed to beneficially own the common units and subordinated units owned by Chesapeake Exploration, L.L.C. Chesapeake has an Investment Committee consisting of Robert D. ("Doug") Lawler, Domenic J. ("Nick") Dell'Osso, Jr. and Jennifer M. Grigsby that will exercise voting and investment control with respect to Chesapeake's common and subordinated units.

(b) Security Ownership of Management

Not Applicable

(c) Changes in Control

The registrant knows of no arrangement, including any pledge by any person of securities of the registrant or its parent, the operation of which may at a subsequent date result in a change of control of the registrant.

ITEM 13. Certain Relationships and Related Transactions and Director Independence

Under the terms of the Trust agreement, the Trust pays an annual administrative fee to the Trustee of $175,000 (which may be adjusted beginning on January 1, 2015), paid in four quarterly installments of $43,750 each and is billed in arrears. As the Trust uses the modified cash basis of accounting, general and administrative expenses in the Trust's statements of distributable income for the years ended December 31, 2013 and 2012 include $175,000 for administrative fees paid to the Trustee. The Trustee did not receive a fee for the six months ended December 31, 2011.

Administrative Services Agreement

On November 16, 2011, the Trust entered into an administrative services agreement with Chesapeake, effective July 1, 2011, pursuant to which Chesapeake provides the Trust with certain accounting, tax preparation, bookkeeping and information services related to the Royalty Interests and the registration rights agreement. In return for the services provided by Chesapeake under the administrative services agreement, the Trust pays Chesapeake, on a quarterly basis, a total annual fee of $200,000, which will remain fixed for the life of the Trust. 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.

Additionally, the administrative services agreement established Chesapeake as the Trust's hedge manager, pursuant to which Chesapeake has the authority, on behalf of the Trust, to administer the Trust's derivative contracts. As hedge manager, Chesapeake also has authority to terminate, restructure or otherwise modify all or any portion of the derivative contracts to the extent that Chesapeake reasonably determines, acting in good faith, that the volumes hedged under such contracts exceed, or are expected to exceed, the combined estimated production attributable to the Royalty Interests over the periods hedged. However, in fulfilling its role as hedge manager, Chesapeake is not acting as a fiduciary for the Trust and has no affirmative duty to modify any of the Trust's derivative contracts, except as required by the derivative contracts. Moreover, under the Trust Agreement, Chesapeake is indemnified by the Trust for any actions it takes in this regard.

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.

Registration Rights Agreement

On November 16, 2011, the Trust entered into a registration rights agreement for the benefit of Chesapeake and certain of its affiliates (each, a “holder”). Pursuant to the registration rights agreement, the Trust agreed, for the benefit of each holder, to register the Trust units held by each such holder for resale under the Securities Act. Specifically, the Trust agrees:

- subject to certain lock-up restrictions, 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.

Development Agreement

On November 16, 2011, the Trust entered into a development agreement with Chesapeake, effective July 1, 2011, that obligates Chesapeake to drill and complete, or cause to be drilled and completed, all of the Development Wells on or prior to June 30, 2016. Additionally, until Chesapeake has met its obligation to drill the Development Wells, Chesapeake agreed not to drill and complete, or permit any other person within its control to drill and complete, any well in the AMI other than the Development Wells. A wholly owned subsidiary of Chesapeake granted to the Trust a lien (the "Drilling Support Lien") on its 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 the Trust pursuant to the Drilling Support Lien or through its exercise of other remedies against Chesapeake for failure to meet its drilling obligation initially could not exceed $262.7 million. As Chesapeake fulfills its drilling obligation over time, the total amount that may be recovered will be proportionately reduced and the completed Development Wells will be released from the lien. If Chesapeake does not fulfill its drilling obligation by June 30, 2016, the Trust may foreclose on any remaining interest in the AMI that is subject to the Drilling Support Lien. Any amounts actually recovered in a foreclosure action would be applied to the completion of Chesapeake's drilling obligation and would not result in any distribution to the Trust unitholders.

Under the development agreement, 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 receives proportionate credit.

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 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.

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. Until Chesapeake has satisfied its drilling obligation, it will not be permitted to drill or complete any well in the Colony Granite Wash formation 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.

Chesapeake's drilling activity with respect to the Development Wells is consistent with its intent to meet the drilling obligation contemplated by the development agreement. As of March 10, 2014, Chesapeake had drilled and completed a total of 79 wells in the AMI (approximately 87.9 Development Wells as calculated under the development agreement), reducing the amount that may be recovered under the Drilling Support Lien to approximately $67.1 million, and had drilled, or caused to be drilled, two additional wells in the AMI that were awaiting completion.

ITEM 14. Principal Accountant Fees and Services

Estimated fees for services performed by PricewaterhouseCoopers L.L.P. for the years ended December 31, 2013 and 2012 and the six months ended December 31, 2011 are:

	Year Ended December 31, 2013	Year Ended December 31, 2012	Six Months Ended December 31, 2011
Audit Fees[(1)]	$210,000	$203,000	$175,000
Audit-Related Fees	—	—	—
Tax Fees	481,456	466,245	307,276
All Other Fees	—	—	—
Total	$691,456	$669,245	$482,276

(1) Fees for audit services in 2013 and 2012 included fees for the reviews of the Trust's quarterly financial statements.

As a modified cash basis entity the Trust will expense these fees when paid.

As referenced in Item 10, Directors, Executive Officers and Corporate Governance, above, the Trust has no audit committee, and as a result, has no audit committee pre-approval policy with respect to fees paid to PricewaterhouseCoopers L.L.P.

PART IV

ITEM 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report:

Financial Statements. Chesapeake Granite Wash Trust's financial statements are included in Item 8 of this Annual Report.

Exhibits. The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3.1	Certificate of Trust of Chesapeake Granite Wash Trust.	S-1	333-175395	3.1	7/7/2011		
3.2	Amended and Restated Trust Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake Exploration, L.L.C., The Bank of New York Mellon Trust Company, N.A., as Trustee, Trustee and The Corporation Trust Company, as Delaware Trustee.	8-K	001-35343	3.1	11/21/2011		
10.1	Perpetual Overriding Royalty Interest Conveyance (PDP), dated as of November 16, 2011, by and between Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.1	11/21/2011		
10.2	Perpetual Overriding Royalty Interest Conveyance (PUD), dated as of November 16, 2011, by and between Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.2	11/21/2011		
10.3	Term Overriding Royalty Interest Conveyance (PDP), dated as of November 16, 2011, by and between Chesapeake Exploration, L.L.C. and Chesapeake E&P Holding Corporation.	8-K	001-35343	10.3	11/21/2011		
10.4	Term Overriding Royalty Interest Conveyance (PUD), dated as of November 16, 2011, by and between Chesapeake Exploration,	8-K	001-35343	10.4	11/21/2011		

	L.L.C. and Chesapeake E&P Holding Corporation.				
10.5	Assignment of Term Overriding Royalty Interests, dated as of November 16, 2011, by and between Chesapeake E&P Holding Corporation and Chesapeake Granite Wash Trust.	8-K	001-35343	10.5	11/21/2011
10.6	Administrative Services Agreement, dated as of November 16, 2011, by and between Chesapeake Energy Corporation and Chesapeake Granite Wash Trust.	8-K	001-35343	10.6	11/21/2011

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10.7	Development Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.7	11/21/2011		
10.8	Drilling Support Mortgage, dated as of November 16, 2011, by and between Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.8	11/21/2011		
10.9	Registration Rights Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.9	11/21/2011		
10.10	Derivative Contract, dated as of November 16, 2011, by and between Morgan Stanley Capital Group Inc. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.10	11/21/2011		
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 - Trustee's Vice President.					X	
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Trustee's Vice President						X
99.1	Report of Ryder Scott Company, L.P.					X	

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: March 13, 2014

CHESAPEAKE GRANITE WASH TRUST

By:	THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A, Trustee
By:	/s/ Michael J. Ulrich Michael J. Ulrich Vice President

The registrant, Chesapeake Granite Wash Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available, and none have been provided. In signing the report above, the Trustee does not imply that it has performed any such function or that such function exists pursuant to the terms of the Trust Agreement under which it serves.

EXHIBIT INDEX

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