CHESAPEAKE GRANITE WASH TRUST
Form 10-K
March 21, 2018

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, 2017
[ ] 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
601 Travis Street, Floor 16

Houston, Texas	77002
(Address of principal executive offices)	(Zip Code)

(512) 236-6555
(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, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [ ]	Accelerated filer [ ]	Non-accelerated filer [X]	Smaller reporting company [ ]	Emerging growth company [ ]

(Do not check if a smaller
reporting company)

If emerging growth company indicate by check mark if the registrant has elected not to use the extended transition period from complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. [ ]

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 $2.35 on June 30, 2017, was approximately $54 million.

As of March 20, 2018, 46,750,000 Common 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
2017 ANNUAL REPORT ON FORM 10-K
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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.

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 40,500 gross acres (26,400 net acres) held by Chesapeake as of December 31, 2017.

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. Oil equivalent is based on six mcf of natural gas to one barrel of oil or one barrel of NGL. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Despite holding this ratio constant at six mcf to one bbl, prices have historically often been higher or substantially higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower or substantially lower.

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

Completion. The process of treating a drilled well followed by the installation of permanent equipment for the production of oil, natural gas or natural gas liquids, or in the case of a dry well, 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 (a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment

is relatively minor compared to the cost of a new well and (b) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

Development Well. 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 drilled on properties held by Chesapeake in the AMI and in which the Trust has received an interest.

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

Economically Producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue is determined at the terminal point of oil and natural 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.

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 barrels of oil equivalent.

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). 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 Estimated Future Net Revenues or PV-10 (non-GAAP). When used with respect to oil, natural gas and NGL reserves, present value of estimated future net revenues, or PV-10, means the estimated future revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average oil and natural gas price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date (unless such costs are subject to change pursuant to contractual provisions), without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. 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 income tax expense, the PV-10 and Standardized Measure attributable to the Royalty Interests are the same.

Price Differential. The difference in the price of oil, natural gas or NGL 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. 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, natural gas and NGL produced. Examples of production expenses (sometimes called lifting expenses) are:

- costs of labor to operate the wells and related equipment and facilities;
- repairs and maintenance;
- materials, supplies and fuel consumed as well as supplies utilized in operating the wells and related equipment and facilities;
- property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and
- production taxes.

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. As used in this report, proved reserves has the meaning given to such term in Rule 4-10(a)(22) of Regulation S-X, which states in part 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.

Proved Undeveloped Reserves (PUDs). Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively high expenditure is required. 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.

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 natural gas or related substances to market, and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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

SEC. The United States Securities and Exchange Commission.

Standardized Measure. The discounted future net cash flows relating to proved reserves based on the means of the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average oil and natural gas price during the preceding 12-month period prior to the end of the current reporting period (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period). The standardized measure differs from the PV-10 measure only because the former includes the effects of estimated future income tax expenses.

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.

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 (the "Exchange Act"). 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, natural gas and NGL 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 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,” “co “may,” “foresee,” “seek,” “plan,” “goal,” “assume,” “target,” “should,” “intend," "ability," "will," "would," "forecast" or other 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. These factors should not be construed as exhaustive, and there may also be other risks that we are unable to predict at this time. 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 and expressly disclaim any obligation to do so, except as required by applicable law.

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 601 Travis Street, Floor 16, Houston, Texas 77002, and the telephone number of the Trustee is (512) 236-6555.
The Trustee maintains a website for filings by the Trust with 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. Documents and information on the Trust's website are not incorporated by reference herein.
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 interests in the Producing Wells (the "PDP Royalty Interest") 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, natural gas and NGL production attributable to Chesapeake's net revenue interest in the Producing Wells. The royalty interests in the Development Wells (the "Development Royalty Interest") 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, natural gas and NGL 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 had identical rights and privileges, except with respect to their voting rights and rights to receive distributions as described below.
Prior to their conversion on June 30, 2017, the subordinated units were entitled to receive pro rata distributions from the Trust each quarter if and to the extent there was sufficient cash to provide a cash distribution on the common units that was no less than 80% of the target distribution set forth in the Trust Agreement for the corresponding quarter (the "subordination threshold"). If there was insufficient cash to fund such a distribution on all of the Trust units, the distribution made with respect to the subordinated units was either 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. Prior to the conversion of the subordinated units on June 30, 2017, Chesapeake was 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 was 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, if any, was to be paid to Trust unitholders, including Chesapeake, on a pro rata basis.

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On June 30, 2017, the last day of the fourth full calendar quarter subsequent to Chesapeake's satisfaction of its drilling obligation under the development agreement, the subordinated units automatically converted into common units on a one-for-one basis, and Chesapeake's right to receive incentive distributions with respect to quarters after the 2017 second quarter terminated. All distributions made on common units after September 30, 2017 no longer have the benefit of the subordination threshold, nor are the common units subject to the incentive threshold, and all Trust unitholders share on a pro rata basis in the Trust's distributions.

The distribution for the quarter ended June 30, 2017, which was paid on August 31, 2017, was still subject to the subordination threshold. As a result, distributable income available to unitholders for the three and nine months ended September 30, 2017 was still subject to the subordination threshold. As such, distributable income per common unit as of September 30, 2017 was based upon 35,062,500 common units. Beginning with the November 30, 2017 distribution, the distributable income available to unitholders is based on the 46,750,000 common units that are currently outstanding.

Neither the Trust nor the Trustee is responsible for, or has any control over, any 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, natural gas and NGL produced. However, the Trust is not responsible for costs of marketing services provided by affiliates of Chesapeake. Cash distributions to unitholders will continue to be reduced by the Trust's general and administrative expenses. Through March 31, 2016, cash distributions to unitholders were increased or decreased by the effect of the Trust's derivative contracts, given that the Trust continued to settle the derivative contracts through February 2016. 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, natural gas and NGL 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, natural gas and NGL 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 constituted 25% of the outstanding Trust units. Prior to their conversion on June 30, 2017, the subordinated units were entitled to receive pro rata distributions from the Trust each quarter if and to the extent there was sufficient cash to pay a cash distribution on the common units that was no less than 80% of the target distribution set forth in the Trust Agreement for the corresponding quarter. If there was insufficient cash to fund such a distribution on all of the

common units, the distribution made with respect to the subordinated units was either 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. Prior to the conversion of the subordinated units on June 30, 2017, 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 was 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 was 20% greater than the target distribution for such quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold, if any, was paid to the Trust unitholders, including Chesapeake, on a pro rata basis.

On June 30, 2017, the last day of the fourth full calendar quarter subsequent to Chesapeake's satisfaction of its drilling obligation under the development agreement, the subordinated units automatically converted into common units on a one-for-one basis. Distributions made on common units no longer have the benefit of the subordination threshold, nor are the common units subject to the incentive threshold, and all Trust unitholders share on a pro rata basis in the Trust's distributions.

For the year ended December 31, 2017, the Trust declared and paid the following cash distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit[1]
June 2017 – August 2017	November 30, 2017	$ 0.0657	$ —
March 2017 – May 2017[2]	August 31, 2017	$ 0.1003	$ —
December 2016 – February 2017	June 1, 2017	$ 0.1005	$ —
September 2016 – November 2016	March 2, 2017	$ 0.0912	$ —

(1) For the production periods from September 2016 through May 2017, the distribution per common unit was below the applicable subordination threshold, and no distribution was declared for the subordinated units. For the production period from June 2017 through August 2017 the subordination threshold was no longer applicable. On June 30, 2017, the subordinated units automatically converted into common units on a one-for-one basis. Distributions made on common units no longer have the benefit of the subordination threshold, nor are the common units subject to the incentive threshold, and all Trust unitholders share on a pro rata basis in the Trust's distributions.

(2) Following the Trust's press release dated August 4, 2017, the Trust identified an additional $190,000 to be included in distributable income available to unitholders. The Trust announced a revision to the distribution amount on August 11, 2017. Based upon the revised sales volume and average pricing calculations, the distribution of $0.1003 per common unit, which was calculated on the basis of 35,062,500 common units and excluded the common units issued on June 30, 2017 upon conversion of the Trust's subordinated units, was paid on August 31, 2017.

As of March 20, 2018, Chesapeake owned 23,750,000 common units, which together represent 50.8% of the outstanding Trust units.

Derivative Contracts

All of the Trust's derivative contracts expired on September 30, 2015. The Trust's derivative contracts were intended to manage its exposure to adverse changes in oil prices. On November 16, 2011, Chesapeake novated derivative contracts 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 consisted of fixed-price oil swaps, in which the Trust received a fixed price and paid a floating market price, based on NYMEX

settlement prices, to the counterparty for the underlying commodity of the derivative. The derivative contracts were not qualified for hedge accounting treatment, and therefore all mark-to-market fluctuations were recorded to Trust corpus when cash settled. As a party to these contracts, the Trust received payments directly from its counterparty or was required to pay any amounts owed directly to its counterparty. All swaps were net settled based on the difference between the fixed-price payment and the floating-price payment.

Settlement of the Trust's derivative contracts continued through February 2016. See Note 3 to the financial statements contained in Part II, Item 8 of this Annual Report for further discussion of the derivative contracts.

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. The Trust had no derivative contracts as of December 31, 2017.

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. 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, all of which are common units.

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. 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.

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

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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 Exchange Act, 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 and the development agreement (except with respect to certain matters that do not adversely affect the rights 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, natural gas and NGL 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 and administrative services agreement. The assets of the Trust consist of the Royalty Interests 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 Exchange Act, 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. 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 Contractual Rights and Assets of the Trust and cash and temporary cash investments, and it may not engage in any investment activity except investing cash on hand.

The Trust Agreement provides that the Trustee will not make business decisions affecting the assets of the Trust. However, the Trustee may:

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

In discharging its duty to Trust unitholders, the Trustee may act in its discretion and will be liable to the Trust unitholders only for willful misconduct, bad faith or gross negligence, 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; or
- the sale is approved by the vote of holders representing a majority of the Trust units and a majority of the common units (excluding common units owned by 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.

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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 has been a party to derivative contracts and the Trust previously has had payment obligations under such arrangements. The derivative contracts expired on September 30, 2015, and the Trust does not currently 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's 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. There were no loans outstanding as of December 31, 2017 or December 31, 2016.

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, 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., former 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 initial public offering of its common units (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 Units, the Trust has not requested a ruling from the IRS regarding its U.S. 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 natural gas industry is highly competitive. Chesapeake competes with both major integrated and other independent oil and natural gas companies in all aspects of its business 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. Competitive conditions may be affected by future legislation and regulations as the United States 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 and natural gas production, such as changing prices, domestic and foreign political conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of natural gas pipelines and other transportation facilities, and overall economic conditions. Chesapeake also faces indirect competition from alternative energy sources, including wind, solar and electric power. Chesapeake believes that its technological expertise, combined with its exploration, land, drilling and production capabilities and the experience of its management team enable it to compete effectively.

Recent volatility in oil, natural gas and NGL prices have adversely impacted, and price fluctuations of oil, natural gas and NGL will continue to 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, natural gas and NGL, neither the Trust nor Chesapeake can make reliable predictions of future supply and demand for oil, natural gas and NGL, future oil, natural gas and NGL prices or the effect of future oil, natural gas and NGL prices on the Trust.

Regulation

General

All of Chesapeake's operations are conducted onshore in the United States. The U.S. oil and natural gas industry is regulated at the federal, state and local levels, and some of the laws and regulations that govern its operations carry substantial administrative, civil and criminal penalties for non-compliance. Although Chesapeake has advised the Trustee that Chesapeake believes it is in material compliance with all applicable laws and regulations, and that the cost of compliance with existing requirements will not have a material adverse effect on its financial position, cash flows or results of operations, 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 impact of compliance or non-compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, state and local governments, the courts and federal agencies, such as the U.S. Environmental Protection Agency (EPA), the Federal Energy Regulatory Commission, the Department of Transportation, the Department of Interior and the U.S. Army Corps of Engineers. Chesapeake has advised the Trustee that Chesapeake actively monitors regulatory developments applicable to the industry in order to anticipate, design and implement required compliance activities and systems.

Exploration and Production

The laws and regulations applicable to Chesapeake's exploration and production operations include requirements for permits or approvals 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 following:

- seismic operations;
- the location of wells;
- construction and operations activities, including in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- the method of drilling and completing wells;
- production operations, including the installation of flowlines and gathering systems;
- air emissions and hydraulic fracturing;
- the surface use and restoration of properties upon which oil and natural 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 generation, storage, transportation treatment, recycling or disposal of hazardous waste, or other substances in connection with operations;
- the construction and operation of underground injection wells to dispose of produced water and other liquid oilfield wastes;
- the construction and operation of surface pits to contain drilling muds and other fluids associated with drilling operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Delays in obtaining permits or an inability to obtain new permits or permit renewals could inhibit Chesapeake's ability to execute its drilling and production plans. Failure to comply with applicable regulations or permit requirements could result in revocation of Chesapeake's permits, inability to obtain new permits and the imposition of fines and penalties.

Chesapeake's exploration and production activities are also subject to various resource 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 oil and natural gas properties. In this regard, some states, such as Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas, 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, some states' resource conservation laws establish maximum rates of production from oil and natural gas 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 oil and natural gas Chesapeake can produce and to limit the number of wells and the locations at which Chesapeake can drill.

Hydraulic Fracturing

Hydraulic fracturing is regulated by state and federal oil and gas regulatory authorities, including specifically the requirement to disclose certain information related to hydraulic fracturing operations. Chesapeake follows applicable legal requirements for groundwater protection in its operations that are subject to supervision by state and federal regulators (including the Bureau of Land Management on federal acreage). Furthermore, Chesapeake's well construction practices require the installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into aquifers. Regulatory proposals in some states and local communities have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Federal and state agencies

have continued to assess the impacts of hydraulic fracturing, which could spur further action toward federal and/or state legislation and regulation of hydraulic fracturing activities. For example, the Oklahoma Corporation Commission (OCC) has released guidance to operators in the SCOOP and STACK areas for management of certain seismic activity that may be related to hydraulic fracturing activities. Further restrictions on hydraulic fracturing could make it prohibitive for Chesapeake to conduct operations, and also reduce the amount of oil, natural gas and NGL that Chesapeake is ultimately able to produce in commercial quantities from the Underlying Properties.

Regulation – Environment, Health and Safety

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. These laws and regulations 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 associated with operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species and/or species of special statewide concern or their habitats;
- requiring investigatory and remedial actions to address pollution caused by Chesapeake's operations or attributable to former operations;
- requiring noise, lighting, visual impact, odor and/or dust mitigation, setbacks, landscaping, fencing, and other measures;
- 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);
- restricting or even prohibiting water use based upon availability, impacts or other factors; and
- restricting or prohibiting the injection of water from hydraulic fracturing.

Failure to comply with these laws, regulations and directives 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. 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.

Moreover, local restrictions, such as state or local moratoria, city ordinances, zoning laws and traffic regulations, may restrict or prohibit the execution of Chesapeake's drilling and production plans. In addition, third parties, such as neighboring landowners, may file claims alleging property damage, nuisance or personal injury arising from Chesapeake's operations or from the release of hazardous substances, hydrocarbons or other waste products into the environment.

Chesapeake monitors developments at the federal, state and local levels to inform their actions pertaining to future regulatory requirements that might be imposed to mitigate 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.

Below is a discussion of the major environmental, health and safety laws and regulations that relate to Chesapeake's business. Chesapeake has advised the Trustee that Chesapeake believes that it is in material compliance with these laws and regulations. Chesapeake does not believe that compliance with existing environmental, health and safety laws or regulations will have a material adverse effect on its financial condition, results of operations or cash flow. At this point, however, Chesapeake has advised the Trustee that it cannot reasonably predict what applicable laws, regulations or guidance may eventually be adopted with respect to its operations or the ultimate cost to comply with such requirements.

Hazardous Substances and Waste

Federal and state laws, in particular the federal Resource Conservation and Recovery Act (RCRA), regulate hazardous and non-hazardous wastes. In the course of Chesapeake's operations, it generates petroleum hydrocarbon

wastes such as drill cuttings, produced water and ordinary industrial wastes. Under a longstanding legal framework, certain of these wastes are currently not subject to federal regulations governing hazardous wastes, although they are regulated under other federal and state waste laws. At various times in the past, most recently in December 2016, proposals have been made to amend RCRA or otherwise eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste Chesapeake is required to manage and dispose and would cause Chesapeake, as well as its competitors, to incur significantly increased operating expenses which could adversely affect the Royalty Interest payments due to the Trust.

Federal, state and local laws may also require Chesapeake to remove or remediate wastes or hazardous substances that have been previously disposed or released into the environment. This can include removing or remediating wastes or hazardous substances disposed or released by Chesapeake (or prior owners or operators) in accordance with then current laws, suspending or ceasing operations at contaminated areas, or performing 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 (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 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/or seek recovery of the costs of such actions from responsible classes of persons.

The Underground Injection Control (UIC) Program authorized by the Safe Drinking Water Act 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, which are 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 regulatory agency if the EPA has delegated its UIC Program authority. Because some states have become concerned that the disposal of produced water could under certain circumstances contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal.

Air Emissions

Chesapeake’s operations are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. Among other things, these laws and regulations regulate emissions of air pollutants from various industrial sources, including Chesapeake’s compressor stations and production equipment, and impose various control, 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, as well as changes to state implementation plans for controlling air emissions in regional non-attainment or near-non-attainment areas may require oil and gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies.

Discharges into Waters

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 U.S. waters. Spill prevention, control and countermeasure regulations require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a release of hydrocarbons. 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 and construction activities.

The Oil Pollution Act of 1990 (OPA) establishes strict liability for owners and operators of facilities that release oil into waters of the United States. 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 United States.

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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.

Endangered Species

The Endangered Species Act (ESA) prohibits the taking of 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, Chesapeake believes that it is in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where Chesapeake intends to conduct construction activity or the imposition of seasonal restrictions on construction or operational activities could materially limit or delay its plans.

Global Warming and Climate Change

At the federal level, EPA regulations require Chesapeake to establish and report a prescribed 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 and natural gas that it sells. In recent years, the EPA has considered additional standards of performance to limit methane emissions from oil and gas sources. In 2017, the EPA announced that it is reconsidering these standards and has proposed to stay their requirements. However, the standards currently remain in effect. The potential increase in Chesapeake's operating costs could include new or increased costs to (i) obtain permits, (ii) operate and maintain its equipment and facilities (through the reduction or elimination of venting and flaring of methane), (iii) install new emission controls on its equipment and facilities, (iv) acquire allowances authorizing its greenhouse gas emissions, (v) pay taxes related to its greenhouse gas emissions and (vi) administer and manage a greenhouse gas emissions program. In addition to these federal actions, state governments and/or regional agencies are considering enacting new legislation and/or promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as Chesapeake's equipment and operations.

In addition, the United States was actively involved in the United Nations Conference on Climate Change in Paris, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and “represent a progression” in their nationally determined contributions, which set emissions reduction goals, every five years. In August of 2017, the United States informed the United Nations of its intent to withdraw from the Paris Agreement. The earliest possible effective withdrawal date from the Paris Agreement is November 2020. For further discussion, see Item 1A. Risk Factors - Potential legislative and regulatory actions addressing climate change could significantly impact the oil and gas industry and Chesapeake, causing increased costs and reduced demand for oil and natural gas.

Operating Hazards and Insurance

The oil and natural gas 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 control of well insurance policy with a $50 million single well limit and a $100 million multiple wells limit 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 $250 million comprehensive general liability umbrella insurance policy and a $100 million

pollution liability

insurance 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 and policy limits scale to Chesapeake's working interest percentage in certain situations. 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. Chesapeake's insurance coverage 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 40,500 gross acres (26,400 net acres). As of December 31, 2017 and 2016, the total reserves estimated to be attributable to the Trust were 5,938 mboe (55% natural gas by volume) and 6,601 mboe (59% natural gas by volume), respectively. These amounts include 5,938 mboe of proved developed reserves and no proved undeveloped reserves as of December 31, 2017 and 6,601 mboe of proved developed reserves and no proved undeveloped reserves as of December 31, 2016. The decrease in estimated total reserves attributable to the Trust of 663 mboe is primarily attributable to 2017 production, partially offset by higher oil and gas prices. 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 further discussion of the decrease in reserves.

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, in the Colony Granite Wash, oil and NGL production currently generate more revenue than natural gas production due to higher relative prices for oil and NGL than for natural gas. Development costs for horizontal wells drilled and completed in the AMI during the year ended December 31, 2016 averaged approximately $61.90 per boe. No development costs were incurred in the year ended December 31, 2017 due to the fulfillment of the development obligation to the trust, as a result of which no new wells were drilled in the Colony Granite Wash.

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, 2017, the Trust on average owns a 47.6% net revenue interest in the Producing Wells and a 28.4% net revenue interest in the completed Development Wells. Chesapeake retains 10% of the proceeds from the sales of oil, natural gas and NGL 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, Natural Gas and NGL 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, natural gas and NGL reserves are located within the U.S. The table below sets forth information as of December 31, 2017 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 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, natural gas and NGL reserves attributable to the Royalty Interests. The reserve estimates were prepared by Software Integrated Solutions, Division of Schlumberger Technology Corporation, in accordance with the criteria established by the SEC. Management uses PV-10, which is calculated without deducting estimated future income tax expenses, as a measure of the value of the Company's current proved reserves and to compare relative values among peer companies. We also understand that securities analysts and rating agencies use this measure in similar ways. While estimated future net revenue and the present value thereof are based on prices, costs and discount factors which may be consistent from company to company, the standardized measure of discounted future net cash flows is dependent on the unique tax situation of each individual company. PV-10 should not be considered in isolation or as a substitute for the standardized measure of discounted future net cash flows or any other measure of a company's financial or operating performance presented in accordance with GAAP.

	Proved Reserves				
	Oil (mbbl)	Natural Gas (mmcf)	NGL (mbbl)	Total (mboe)	PV-10 ($ in thousands)
Underlying Properties:					
Developed	1,256	41,728	4,382	12,593	$ 56,701
Undeveloped	—	—	—	—	—
Total	1,256	41,728	4,382	12,593	$ 56,701
Royalty Interests:					
Developed[1]	604	19,657	2,058	5,938	$ 44,617
Undeveloped[1]	—	—	—	—	—
Total	604	19,657	2,058	5,938	$ 44,617

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

	Proved Developed	Proved Undeveloped	Total Proved
	($ in millions)		
Estimated future net revenue[1]	$76,382	$ —	$76,382
Present value of estimated future net revenue (PV-10)[1]	$44,617	$ —	$44,617
Standardized measure[1]			$44,617

(1) Estimated future net revenue represents the estimated future revenue to be generated from the production of proved reserves, net of estimated production and costs, using prices and costs under existing economic conditions as of December 31, 2017. PV-10 is the present value of estimated future net revenue to be generated from the production of proved reserves, discounted at 10% per annum to reflect timing of future cash flows and 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 the Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, as the Trust is not subject to income tax expense, the two measures are the same as of December 31, 2017.

A reconciliation of the standardized measure of discounted future net cash flows to PV-10 is presented above. Neither PV-10 nor the standardized measure of discounted future net cash flows purport to represent the fair value of the proved oil and gas reserves.

The proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil, natural gas and NGL for the period from January 1, 2017 through December 1, 2017, 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's 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	Natural Gas	NGL
	(per bbl)	(per mcf)	(per bbl)
Trailing 12-month average (SEC) pricing	$ 51.34	$ 2.98	$ 16.34
Weighted average wellhead prices (Underlying Properties)	$ 46.63	$ 0.38	$ 22.62
Weighted average wellhead prices (Royalty Interests)	$ 46.64	$ 0.39	$ 22.61

As of December 31, 2017, no Royalty Interests were classified as PUDs.

The annual net decline rate on current producing properties is projected to be 17% from 2018 to 2019, 15% from 2019 to 2020, 13% from 2020 to 2021 and 12% from 2021 to 2022. As of December 31, 2017, of the total proved reserves, 12,593 mboe and 5,938 mboe attributable to the Underlying Properties and the Royalty Interests, respectively, were classified as proved developed producing reserves.

Chesapeake's ownership interest used for calculating proved reserves and the associated estimated future net revenue assumed maximum participation by other parties to Chesapeake's farmout and participation agreements. SEC pricing used for calculating the estimated future net revenues attributable to proved reserves does not reflect actual market prices for oil, natural gas and NGL production sold subsequent to December 31, 2017.

The Trust's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2017, 2016 and 2015, respectively, along with the changes in quantities and standardized measure of such reserves for the three years ended December 31, 2017, 2016 and 2015, respectively, are shown in Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities included in Item 8 of Part II 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 and natural gas that cannot be measured, 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, natural gas and NGL 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 was obligated to drill, cause to be drilled or participate as a non-operator in the drilling of 118 Development Wells by June 30, 2016. Chesapeake had fulfilled its drilling obligation under the development agreement as of June 30, 2016. Chesapeake has retained an

interest in each of the Producing Wells and Development Wells and currently operates approximately 96% of the Producing Wells and completed Development Wells. Prior to fulfilling its commitment to drill the Development Wells, Chesapeake was not allowed to drill or complete, or permit any other person within its control to drill or complete any well in the Colony Granite Wash formation or 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 average net revenue interest in the oil and gas properties underlying the Development Royalty Interest is approximately 63%. 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, natural gas and NGL from the Development Wells.

The Trust was not responsible for any costs related to the drilling of the Development Wells and is not responsible for any other operating or capital costs of the Underlying Properties.

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 Trust did not obtain any amounts from Chesapeake under the Drilling Support Lien during the period in which Chesapeake was drilling the Development Wells, and the Drilling Support Lien has been reduced to zero.

Due to Chesapeake's completion of its drilling obligation under the development agreement, it may now sell all or any part of its retained interest in the Underlying Properties, without the consent or approval of the Trust unitholders. 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.

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.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Development productive	—	—	9	3	6	1
Exploratory productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total	—	—	9	3	6	1

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, 2017. All of the leases associated with the Underlying Properties are held by production and not subject to expiration so long as production continues in paying quantities.

	Developed Acreage[1]		Undeveloped Acreage	
	Gross	Net	Gross	Net
Acreage Held by Chesapeake within the AMI	40,236	26,195	—	—

(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.

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, natural gas and NGL 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, L.L.C. ("CEMLLC"), a wholly owned subsidiary of Chesapeake, markets the majority of Chesapeake's operated production. CEMLLC enters into oil, natural

gas and

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NGL sales arrangements with large aggregators of supply, and these arrangements may be on a month-to-month basis or for a term of up to one year or longer. The oil, natural gas and NGL are sold at market prices and subsequently any applicable post-production expenses will be deducted. CEMLLC 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, natural gas and NGL 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, natural gas and NGL production attributable to Chesapeake's remaining interest in the Underlying Properties.

Post-production expenses are deducted from proceeds paid to the Trust. Williams Partners, L.P. ("WMB"), provides gathering, treating, compression and other post-production services and Enable Midstream Partners, LP ("Enable") (formerly Enogex LLC) provides 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, natural gas and NGL prior to payment being made to Chesapeake or CEMLLC for such production. At other times, Chesapeake or CEMLLC 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 CEMLLC 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, natural gas and NGL 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 WMB under a contract that expires in approximately 11 years. NGL and natural gas are processed at facilities owned by Enable under a contract that expires in 2023 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 WMB or transported by trucks owned by third parties and sold to various counterparties. In the event of a loss of its contracts with WMB or Enable, Chesapeake believes that the availability of other customers and service providers in the area is sufficient to accommodate such loss.

Any new oil, natural gas and NGL 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.

The following table provides revenues and direct operating expenses for the years ended December 31, 2017, 2016 and 2015, as derived from the Underlying Properties' statements of revenues and direct operating expenses.

	Years Ended December 31,		
	2017	2016	2015
	($ in thousands)		
Oil, natural gas and NGL revenues[1]	$25,057	$22,582	$40,665
Direct operating expenses:			
Production expenses excluding taxes	7,616	6,759	10,277
Production taxes	1,248	702	31
Ad valorem taxes	4	6	2
Total direct operating expenses	8,868	7,467	10,310
Revenues in excess of direct operating expenses	$16,189	$15,115	$30,355

(1) Oil, natural gas and NGL 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, 2017, 2016 and 2015.

	Years Ended December 31,		
	2017	2016	2015
Production:			
Oil (mbbls)	227	315	478
Natural gas (mmcf)	5,609	7,423	11,130
NGL (mbbls)	600	714	887
Total production (mboe)	1,762	2,266	3,220
Average sales prices:[1]			
Oil (per bbl)	$42.80	$35.87	$43.58
Natural gas (per mcf)	$0.46	$(0.05)	$0.72
NGL (per bbl)	$21.22	$16.37	$13.30
Average (per boe)	$14.22	$9.96	$12.63
Direct operating expenses:			
Production expenses (per boe)[2]	$4.32	$2.99	$3.19
Production taxes (per boe)[3]	$0.71	$0.31	$0.01

(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 (a) volume produced and (b) prices received for production.

Oil, Natural Gas and NGL Revenues. For the year ended December 31, 2017, oil, natural gas and NGL revenues were $25.1 million compared to $22.6 million and $40.7 million for the years ended 2016 and 2015, respectively. The $2.5 million increase in revenues from 2016 to 2017 was primarily due to an increase in the average sales price of oil, natural gas and NGL. The increase in the price received per boe in 2017 compared to 2016 resulted in a $7.5 million increase in oil, natural gas and NGL revenues. Average oil prices increased $6.93 per bbl, from $35.87 per bbl for the year ended December 31, 2016 to $42.80 per bbl for the year ended December 31, 2017. Average natural gas prices increased $0.51 per mcf, from $(0.05) per mcf for the year ended December 31, 2016 to $0.46 per mcf for the year

ended December 31, 2017. NGL prices increased $4.85 per bbl, from $16.37 per bbl for the year ended December 31, 2016 to $21.22 per bbl for the year ended December 31, 2017. Decreased sales volumes resulted in a $5.0 million decrease in oil, natural gas and NGL revenues, for a net increase in oil, natural gas and NGL revenues of $2.5 million from 2016 to 2017.

The $18.1 million decrease in revenues from 2015 to 2016 was primarily due to a decrease in production and a decrease in the average sales price of oil. Decreased sales volumes resulted in a $12.1 million decrease in oil, natural gas and NGL revenues. The decrease in the sales price received per boe in 2016 compared to the 2015 resulted in a $6.0 million decrease in oil, natural gas and NGL revenues, for a net decrease in oil, natural gas and NGL revenues of $18.1 million from 2015 to 2016.

Production Expenses. For the year ended December 31, 2017, production expenses, excluding production and ad valorem taxes, were $7.6 million compared to $6.8 million and $10.3 million for the years ended 2016 and 2015, respectively. On a unit-of-production basis, production expenses, excluding production taxes and including ad valorem taxes, were $4.32 per boe in 2017 compared to $2.99 and $3.19 per boe in 2016 and 2015, respectively. The increase in production expense from 2016 to 2017 is due to increases in repair and maintenance costs.

Production Taxes. For the year ended December 31, 2017, production taxes were $1.2 million, compared to $0.7 million and a nominal amount for the years ended 2016 and 2015, respectively. On a unit-of-production basis, production taxes were $0.71 per boe in 2017 compared to $0.31 per boe in 2016 and $0.01 per boe in 2015. The increase in production taxes from 2016 to 2017 is due to the increase in commodity prices. Severance tax exemptions related to economically at risk wells for prior periods were realized in 2015, causing production taxes per boe in 2015 to be significantly lower than production taxes per boe in 2016.

The Reserve Report for the Underlying Properties and the Royalty Interests

The oil, natural gas and NGL reserves in this Annual Report were estimated by Software Integrated Solutions, Division of Schlumberger Technology Corporation ("Software Integrated Solutions"). The process to review and estimate the reserves begins 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 is reviewed by various levels of Chesapeake management for accuracy before consultation with Software Integrated Solutions. Software Integrated Solutions was consulted with regularity during the reserve estimation process to review properties, assumptions, and any new data available. Internal reserve estimates and methodologies are compared to Software Integrated Solutions' estimates and methodologies to test the reserve estimates and conclusions before the reserve estimates are included in this Annual Report. Additionally, Chesapeake's senior management reviews and approves 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. Her qualifications include the following:

- Over 15 years of practical experience in the oil and gas industry, with 11 years in reservoir engineering;
- Bachelor of Science degree in Geology and Environmental Sciences;
- Master's Degree in Petroleum and Natural Gas Engineering;
- Executive MBA; 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. Each of Chesapeake's Corporate Reserves Advisors has significant experience in reserve estimation. Each of its engineering technicians has a minimum of a four-year degree in mathematics, economics, finance or other technical/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 skills and analytical techniques.

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

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

supervision. All material changes are reviewed and approved by Chesapeake's Corporate Reserve Advisors.

- Chesapeake's Corporate Reserves Department reviews all of Chesapeake's and the Trust's proved reserves at the close of each quarter.
- Each quarter, Chesapeake's Reservoir Managers, the Director - Corporate Reserves, the Vice Presidents of its business units, the Vice President of Corporate and Strategic Planning and the Executive Vice President - Exploration and Production review all significant reserves changes and all new proved undeveloped reserves additions.
- Chesapeake's Corporate Reserves Department reports independently of Chesapeake's operations.

Technologies. The reserve report was prepared using decline curve analysis to determine the reserves of individual Producing Wells, as defined by the SEC. 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.

Software Integrated Solutions. Chesapeake engaged Software Integrated Solutions, a third-party engineering firm, to prepare all of the Trust's estimated proved reserves as of December 31, 2017. A copy of the report issued by the engineering firm is filed with this report as Exhibit 99.1. The qualifications of the technical person at the firm primarily responsible for overseeing the 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 geologist licensed in the Commonwealth of Pennsylvania;
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and
- Bachelor of Science degree in Geological Sciences.

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.

ITEM 1A. Risk Factors

Risks Related to the Units

Producing oil, natural gas and NGL on the Underlying Properties is a high-risk activity with many uncertainties. Any delays or reductions in production could decrease cash available for distribution to unitholders.

Producing oil, natural gas and NGL can be unprofitable 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 depended 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. Production operations on the Underlying Properties may be curtailed, delayed or canceled as a result of various factors, including the following:

- unusual or unexpected geological formations and miscalculations or irregularities in formations;
- 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;
- pipe or cement failures and casing collapses;
- pressures, fires, blowouts and explosions;
- lost or damaged service tools;
- uncontrollable flows of oil, natural gas and NGL water or drilling fluids;
- natural disasters;
- environmental hazards, such as oil, natural gas and NGL 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, natural gas and NGL prices; and
- title problems affecting the Underlying Properties.

If 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.

Oil, natural gas and NGL prices fluctuate widely, and depressed prices for an extended period of time are likely to have a material adverse effect on proceeds to the Trust and cash distributions to unitholders.

The Trust's reserves and quarterly cash distributions depend primarily upon the prices realized from the sales of oil, natural gas and NGL. Chesapeake requires substantial expenditures to replace reserves, sustain production and fund its business plans. Low oil, natural gas and NGL prices can negatively affect the amount of cash available for capital expenditures and debt repayment and the ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on Chesapeake’s financial condition, results of operations, cash flows and reserves and the Trust’s reserves and quarterly cash distributions. Historically, the markets for oil, natural gas and NGL have been volatile and they are likely to continue to be volatile. Wide fluctuations in oil, natural gas and NGL prices may result from relatively minor changes in the supply of or demand for oil, natural gas and NGL, market uncertainty and other factors that are beyond the control of the Trust and Chesapeake, including:

- domestic and worldwide supplies of oil, natural gas and NGL, including U.S. inventories of oil and natural gas reserves;
- weather conditions;
- changes in the level of consumer and industrial demand;
- the price and availability of alternative fuels;

- the effectiveness of worldwide conservation 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;
- 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 natural gas producing regions;
- acts of terrorism; and
- domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. Oil and natural gas prices remained low throughout 2016 and 2017. Lower oil, natural gas and NGL prices have reduced, and could continue to reduce, proceeds to which the Trust is entitled and may ultimately reduce the amount of oil, natural gas and NGL that is economic to produce from the Underlying Properties. As a result, Chesapeake or any third-party operator of any of the Underlying Properties could determine during periods of low oil, natural gas and NGL prices to shut in or curtail production from wells on the Underlying Properties. In addition, the operator of the Underlying Properties could determine during periods of low oil, natural gas and NGL prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, Chesapeake or any third-party operator may abandon any well or property if it reasonably believes that the well or property can no longer produce oil, natural gas and NGL 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, natural gas and NGL prices also reduces the accuracy of target distributions used to calculate the subordination and incentive thresholds.

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. Estimates of proved reserves and estimated future net revenues from proved reserves are based upon various assumptions, including assumptions required by the SEC relating to oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil, natural gas and NGL reserves is complex and involves significant decisions and assumptions associated with geological, geophysical, engineering and economic data for each well. Therefore, these estimates are subject to further revisions.

Actual future production attributable to the Royalty Interests, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2017, none of the Trust’s estimated proved reserves were undeveloped.

The present values included in this report do not represent the current market value of the Trust's estimated reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs as of the date of the estimates. The price on the date of estimate is calculated as the average oil and natural gas price

during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2017 present value is based on $51.34 per bbl of oil and $2.98 per mcf of natural gas before basis differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. Any changes in consumption or in governmental regulations will also affect the actual future net cash flows from our production. In addition, the 10% discount factor which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor. Interest rates in effect from time to time and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor.

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, as defined by the SEC, 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 2017, the Trust recorded downward reserve revisions primarily due to a decrease in production offset by higher oil and gas prices. During 2016, the Trust recorded downward reserve revisions primarily due to higher-than-expected pressure depletion within certain areas of the AMI. During 2015, the Trust recorded significant downward reserve revisions primarily due to a decrease in commodity prices and the removal of PUDs that were not part of Chesapeake's drilling plan within 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.

Chesapeake's ability to satisfy its obligations to the Trust depends on its financial position, and in the event of 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 was obligated to drill and complete, or participate as a non-operator in the drilling and completion of, the Development Wells at its own expense. As of June 30, 2016, Chesapeake had fulfilled its drilling and completion obligation under the development agreement. The conveyances provide that Chesapeake is obligated to market, or cause to be marketed, the oil, natural gas and NGL 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. Chesapeake's ability to perform its 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, natural gas and NGL, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

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 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.

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.

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 operate the Development Wells.

Pursuant to the development agreement between Chesapeake and the Trust, Chesapeake was obligated to, and did, drill and complete the equivalent of 118 Development Wells in the AMI as of June 30, 2016. Certain Development Wells drilled by Chesapeake are currently operated by third-party operators. 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.

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. The failure of an operator to adequately perform operations could reduce the revenues distributable to the Trust and the amount of cash distributable to the Trust unitholders.

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

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

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

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, natural gas and NGL 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, natural gas and NGL 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, natural gas and NGL production from the Underlying Properties.

The amount of oil, natural gas and NGL that may be produced and sold from any well to which the Underlying Properties relate is subject to the availability of gathering, transportation and processing facilities. Even where such facilities are available, services from such facilities are subject to curtailment in certain circumstances, such as by reason of weather conditions, pipeline interruptions due to scheduled and unscheduled maintenance, failure of tendered oil, natural gas and NGL 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.

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, natural gas and mineral leaseholds. Chesapeake's inability or failure to cure title defects could 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, natural gas and NGL 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 are currently 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, natural gas and NGL from, or future development of, the Underlying Properties.

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

Future maintenance may affect the quantity of proved reserves that can be economically produced from the Underlying Properties to which the wells relate. The timing and size of these projects will depend on, among other

factors, the market prices of oil, natural gas and NGL. Chesapeake has no contractual obligation to the Trust to make capital expenditures on the Underlying Properties in the future. Furthermore, for properties on which Chesapeake is not designated as the operator, Chesapeake has no control over the timing or amount of those capital expenditures. Chesapeake also has the right not to participate in the capital expenditures on properties for which it is not the operator, in which case Chesapeake and the Trust will not receive the production resulting from such capital expenditures. If Chesapeake or other operators of the wells to which the Underlying Properties relate do not implement maintenance projects when warranted, the future rate of production decline of proved reserves may be higher than the rate currently expected by Chesapeake or estimated in the reserve reports.

The Trust Agreement 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 prices realized by Chesapeake for oil, natural gas and NGL produced from the Underlying Properties and the NYMEX or other benchmark price of oil or natural gas could reduce the proceeds to the Trust and therefore the cash distributions by the Trust and the value of Trust units.

The prices received for Chesapeake's oil, natural gas and NGL 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, natural gas and NGL and the benchmark price for oil, natural gas and NGL 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 and Trust expenses.

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

- the Trust's share of the expenses incurred by Chesapeake to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and NGL (excluding costs of marketing services provided by Chesapeake);
- the Trust's share of applicable taxes on the oil, natural gas and NGL; and
- Trust administrative expenses, including fees paid to the Trustee and the Delaware Trustee, the annual administrative services fee payable to Chesapeake, tax return and Schedule K-1 preparation and mailing costs, independent auditor fees and registrar and transfer agent fees, costs associated with annual and quarterly reports to unitholders and certain internal expenses of the Trust incurred pursuant to the registration rights agreement.

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.

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 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, natural gas and NGL at that time. There can be no assurance that the prices of oil, natural gas and NGL 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 23,750,000 common units. 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:

- 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. For example, 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. Chesapeake may make decisions with respect to expenditures and decisions to allocate resources to projects in other areas that adversely affect the Underlying Properties, including reducing expenditures on these properties, which could cause oil, natural gas and NGL production to decline at a faster rate and thereby result in lower cash distributions by the Trust in the future.
- 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.
- 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, it 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. There were no loans outstanding as of December 31, 2017 or December 31, 2016.

Chesapeake may sell all or a portion of its retained interest in the Underlying Properties, subject to and burdened by the Royalty Interests; any such purchaser could have a weaker financial position and/or be less experienced in oil, natural gas and NGL 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, 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, natural gas and NGL 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 producing operations can be hazardous and may expose Chesapeake to liabilities.

Oil and natural gas producing operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, oil spills, severe weather, natural disasters, groundwater contamination 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. For non-operated properties, Chesapeake is dependent on the operator for operational and regulatory compliance. A temporary or permanent halt of the production and sales of oil, natural gas and NGL at any of the Underlying Properties could also reduce Trust distributions by reducing the amount of proceeds available for distribution.

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.

A material event such as those described above could expose Chesapeake to liabilities, monetary penalties or interruptions in its business operations. While Chesapeake may maintain insurance against some, but not all, of the risks described above, its insurance may not be adequate to cover casualty losses or liabilities, and its insurance does not cover penalties or fines that may be assessed by a governmental authority. For certain risks, such as political risk, business interruption, war, terrorism and piracy, Chesapeake has limited or no insurance coverage. Also, in the future Chesapeake may not be able to obtain insurance at premium levels that justify its purchase. The occurrence of a significant event against which Chesapeake is not fully insured may expose it to liabilities.

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

Development activities require the use of water. For example, hydraulic fracturing requires the use and disposal of significant quantities of water. In certain areas, there may be insufficient local aquifer capacity to provide a source of water for operations. Chesapeake's inability to secure sufficient amounts of water, or to dispose of or recycle the water used in its operations, could adversely impact the development of the Underlying Properties. The imposition of new environmental initiatives and regulations, such as the Oklahoma Corporation Commission volume reduction plans for oil and natural gas disposal wells injecting wastewater into the Arbuckle formation and the EPA’s June 2016 pretreatment standards for wastewater, could further restrict Chesapeake's ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water and other materials associated with the exploration, development or production of oil and natural gas.

Potential legislative and regulatory actions addressing climate change could significantly impact the oil and gas industry and Chesapeake, causing increased costs and reduced demand for oil and natural gas.

Various state governments and regional organizations have considered enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as our equipment and operations. At the federal level, the EPA has issued regulations that require us to establish and report a prescribed inventory of greenhouse gas emissions and published a final rule in June 2016 to reduce methane emissions from oil and gas production. The EPA more recently published a proposal to stay certain portions of the rule. As a result, the implications of the 2016 standards are uncertain. Additional legislative and/or regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require us to incur additional operating costs and could adversely affect demand for the oil and natural gas that we sell. The potential increase in our operating costs could include new or increased costs to obtain permits, operate and maintain our equipment and facilities, install new emission controls on our equipment and facilities, acquire allowances to authorize our greenhouse gas emissions, pay taxes related to our 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.

The Paris Agreement will require countries to review and “represent a progression” in their nationally determined contributions, which set emissions reduction goals, every five years. In August 2017, the United States informed the United Nations of its intent to withdraw from the Paris Agreement. The earliest possible effective withdrawal date from the Paris Agreement is November 2020. The Paris Agreement could further drive regulation in the United States. Restrictions on emissions of methane or carbon dioxide that have been or may be imposed in various states, or at the federal level could adversely affect the oil and gas industry. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for oil and natural gas. Finally, we note that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as higher sea levels, increased frequency and severity of storms, droughts, floods, and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

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 Trust unitholders would be substantially reduced.

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

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

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 for tax years beginning after 2017 is 21%, 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 state budget deficits and other reasons, several states have been 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 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.

U.S. federal tax reform legislation informally known as the Tax Cuts and Jobs Act (the “Tax Act”) was enacted December 22, 2017, and makes significant changes to the federal income tax rules applicable to both individuals and entities, including changes to the effective tax rate on an individual or other non-corporate unitholder’s allocable share of certain income from a publicly traded partnership. The Tax Act is complex and lacks administrative guidance, thus, unitholders should consult their tax advisor regarding the Tax Act and its effect on an investment in Trust units.

For taxable years beginning after 2017, the highest marginal U.S. federal income tax rates applicable to ordinary income and long-term capital gains of individuals are 37% and 20%, respectively. Individual unitholders may be eligible for a deduction for tax years beginning after 2017 generally equal to 20% of the Trust’s domestic income and 20% of any recapture income of the unitholder on the sale of Trust units, which could reduce the individual’s effective tax rate on income from the Trust. However, such deduction will not be available after 2025 unless Congress extends it. In addition, 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.

With respect to Oklahoma production tax, it has been assumed that the effective tax rate on the oil, natural gas and NGL attributable to the Trust will be approximately 2.0% for the first three years of production for each well spudded on or after July 1, 2015, and approximately 7.0% thereafter. These rates are subject to change by new legislation at any time.

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 changes or differing interpretations at any time. For example, from time to time, the President and members of Congress propose and consider substantive changes to the existing U.S. federal income tax laws that affect publicly traded partnerships. Further, final regulations under Section 7704(d)(1)(E) of the Internal Revenue Code of 1986, as amended, interpret the scope of the qualifying income requirements for publicly traded partnerships by providing industry-specific guidance.

Any modification to the U.S. federal income tax laws or interpretations thereof (including administrative guidance relating to the Tax Act) may be applied retroactively and could make it more difficult or impossible for the Trust to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes or otherwise adversely affect our business, financial condition or results of operations. The Trust is unable to predict whether any changes or other proposals will ultimately be enacted, or whether any adverse interpretations will be used. Any such changes or interpretations could negatively impact the value of an investment in the 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

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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.

For tax years beginning after December 31, 2017, if the IRS makes audit adjustments to the Trust's income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from the Trust. To the extent possible under the new rules, the Trust may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if eligible, issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. Although the Trust may elect to have Trust unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, current Trust unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such Trust unitholders did not own units in the Trust during the tax year under audit. If, as a result of any such audit adjustment, the Trust is required to make payments of taxes, penalties and interest, cash available for distribution to Trust unitholders might be substantially reduced. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

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 could result in differing tax consequences. For example, some of the Trust income allocated to organizations exempt from U.S. 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.

Final Treasury Regulations allow publicly traded partnerships to use a similar monthly simplifying convention to allocate tax items among transferors and transferees, although these regulations do not specifically authorize all aspects 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.

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 U.S. 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.

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 a number of lawsuits in process that involve properties in the AMI and has claims that exceed $40,000 individually or in aggregate. The Trust is 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 with other pending or threatened lawsuits or disputes, 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 2016 (January 1 through March 31)	$3.43	$1.56
Second Quarter 2016 (April 1 through June 30)	$3.83	$1.81
Third Quarter 2016 (July 1 through September 30)	$2.45	$1.96
Fourth Quarter 2016 (October 1 through December 31)	$2.45	$2.10
First Quarter 2017 (January 1 through March 31)	$3.85	$2.25
Second Quarter 2017 (April 1 through June 30)	$2.85	$2.20
Third Quarter 2017 (July 1 through September 30)	$2.50	$2.10
Fourth Quarter 2017 (October 1 through December 31)	$2.30	$1.75

As of March 20, 2018, 46,750,000 common units representing beneficial interests in Chesapeake Granite Wash Trust were outstanding and held by 13 certified unitholders of record. Of such units, 35,062,500 were issued on November 16, 2011 and 11,687,500 of such units were subordinated units that were converted into common units on a one-for-one basis as of June 30, 2017. 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 2016 [1]	$0.2195	$ —
Second Quarter 2016	$0.0403	$ —
Third Quarter 2016	$0.0734	$ —
Fourth Quarter 2016	$0.0857	$ —
First Quarter 2017	$0.0912	$ —
Second Quarter 2017	$0.1005	$ —
Third Quarter 2017 [2]	$0.1003	$ —
Fourth Quarter 2017	$0.0657	$ —

(1) A distribution of $0.2195 per common unit was paid on March 1, 2016 to common unitholders of record, as of February 19, 2016, other than Chesapeake. Chesapeake received $0.0369 per common unit and waived its right to receive the higher distribution on its units with respect to the quarter ended December 31, 2015. The Trust's distributable income for the quarter ended December 31, 2015 was $0.1567 per common unit. As the distributable income per common unit was below the subordination threshold, no distribution was declared for the subordinated units.

(2) Following the Trust's press release dated August 4, 2017, the Trust identified an additional $190,000 to be included in distributable income available to unitholders. The Trust announced a revision to the distribution amount on August 11, 2017. Based upon the revised sales volume and average pricing calculations, the distribution of $0.1003 per common unit, which was calculated on the basis of 35,062,500 common units and excluded the common units issued on June 30, 2017 upon conversion of the Trust's subordinated units, was paid on August 31, 2017.

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. As of December 31, 2017 and December 31, 2016 there were no loans outstanding.

Equity Compensation Plans

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

Recent Sales of Unregistered Securities

None.

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, 2017, 2016, 2015, 2014 and 2013:

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	($ in thousands, except per unit data)				
Royalty income	$15,665	$12,431	$36,377	$95,997	$114,010
Distributable income	$13,311	$12,485	$53,315	$83,984	$104,868
Distributable income per common unit	$0.3577	$0.3561	$1.5206	$2.3953	$2.7171
Distributable income per subordinated unit	$—	$—	$—	$—	$0.8214

Assets, Liabilities and Trust Corpus

The following is the balance of total assets, total liabilities and trust corpus as of December 31, 2017, 2016, 2015, 2014 and 2013:

	December 31,				
	2017	2016	2015	2014	2013
	($ in thousands)				
Total Assets	$28,372	$31,938	$63,391	$256,604	$318,288
Total Liabilities	$768	$—	$175	$—	$8,071
Trust Corpus	$27,604	$31,938	$63,216	$256,604	$310,217

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, through March 31, 2016, net gains on settlements of 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 drilled in the Colony Granite Wash play on properties within the AMI. Chesapeake was 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 was obligated to either complete and tie into production or plug and abandon each Development Well. As of June 30, 2016, Chesapeake had fulfilled its drilling obligation under the development agreement.

The Trust was not responsible for any costs related to the drilling of the Development Wells and is not responsible for any other operating or capital costs of the Underlying Properties, and Chesapeake was 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 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, natural gas and NGL 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, natural gas and NGL 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, natural gas and NGL 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 included net settlements under these derivative contracts. The fair value of the derivative contracts as of December 31, 2015 was a net asset of $2.1 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, 2017, four distributions were paid. See Liquidity and Capital Resources below and Note 6 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 fluctuates from quarter to quarter depending on several factors, including:

- timing of initial production and sales from the Development Wells;
- oil, natural gas and NGL prices received;
- volumes of oil, natural gas and NGL produced and sold;
- 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

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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 generally include royalties attributable to sales of oil, natural gas and NGL 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, 2017, the Trust received payments on the Royalty Interests representing royalties attributable to proceeds from sales of oil, natural gas and NGL for September 1, 2016 through August 31, 2017. During the year ended December 31, 2016, the payments received by the Trust represented royalties attributable to proceeds from sales of oil, natural gas and NGL for September 1, 2015 through August 31, 2016. During the year ended December 31, 2015, the payments received by the Trust represented royalties attributable to proceeds from sales of oil, natural gas and NGL for September 1, 2014 through August 31, 2015.

The Trust’s income available for distribution throughout 2016 and 2017 has been adversely affected by several factors. The Trust's revenues and distributable income available to unitholders have been and will continue to be adversely affected if commodity prices or production remain at current levels or decline further. For each of the quarterly production periods from September 1, 2016 to November 30, 2016, December 1, 2016 to February 29, 2017 and March 1, 2017 to May 31, 2017, the Trust paid a common unit distribution below the applicable subordination threshold and no subordinated distribution was paid. For the quarterly production period from June 1, 2017 to August 31, 2017 the threshold is no longer applicable as the subordination threshold terminated on June 30, 2017 and is no longer applicable for any future distribution.

Low levels of future production and any future depression in commodity prices will continue to reduce the Trust’s revenues and distributable income available to unitholders.

During the year ended December 31, 2017, the Trust recognized no impairments of the Royalty Interests. During the years ended December 31, 2016 and 2015, the Trust recognized approximately $22.6 million and $154.2 million, respectively, in impairments of the Royalty Interests primarily due to a decrease in commodity prices used to calculate the proved reserves attributable to the Trust's interest in the Underlying Properties and lower proved reserve quantities attributable to higher-than-expected pressure depletion within certain areas of the AMI. See Note 2 to the financial statements contained in Part II, Item 8 of this Annual Report for further discussion of the impairments.

Distributable Income. The Trust's distributable income was $13.3 million for the year ended December 31, 2017, compared to $12.5 million for the year ended December 31, 2016.

The $0.8 million increase from 2016 to 2017 was primarily due to an increase in the average realized prices received from sales of oil, natural gas and NGL, offset by a decrease in production volumes in the production period from September 1, 2016 to August 31, 2017 (the "2017 production period") as compared to the production period from September 1, 2015 to August 31, 2016 (the "2016 production period"). The increase in the price received per boe in the 2017 production period compared to the 2016 production period resulted in a $3.2 million increase in distributable income offset by decreased sales volumes that resulted in a $2.4 million decrease in distributable income, for a net increase in distributable income of $0.8 million. Distributable income paid to the Trust unitholders during the year ended December 31, 2015 and attributable to production from September 1, 2014 to August 31, 2015 (the "2015 production period") was $53.3 million. The $40.8 million decrease in the Trust's distributable income for the 2016 production period as compared to the 2015 production period was the result of a decrease in the average realized prices received from sales of oil, natural gas and NGL and a decrease in production volumes in the 2016 production period as compared to the 2015 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, 2017 and attributable to the 2017 production period were $0.3577 per common unit and no subordinated unit distributions were paid as compared to $0.3561 per common unit and no subordinated unit distributions were paid for the year ended December 31, 2016 and attributable to the 2016 production period. Cash distributions were $1.5206 per common unit and no subordinated unit distributions were paid for the year ended December 31, 2015 and attributable to the 2015 production period. Distributable income for the production periods described above was calculated as follows:

	Years Ended December 31,		
	2017	2016	2015
	($ in thousands, except per unit data)		
Revenues:			
Royalty income[1]	$15,665	$12,431	$36,377
Total revenues	15,665	12,431	36,377
Income (Expenses):			
Production taxes	(669)	(449)	(681)
Trust administrative expenses[2]	(1,685)	(1,606)	(1,466)
Derivative settlement gain	—	2,109	19,085
Total income (expenses)	(2,354)	54	16,938
Distributable income available to unitholders	$13,311	$12,485	$53,315
Distributable income per common unit (46,750,000 common units at December 31, 2017 and 35,062,500 common units at December 31, 2016 and December 31, 2015)	$0.3577	$0.3561	$1.5206
Distributable income per subordinated unit (0 subordinated units at December 31, 2017 and 11,687,500 subordinated units at December 31, 2016 and December 31, 2015)[3][4]	$—	$—	$—

(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld (used).

(3) For the years ended December 31, 2016 and 2015, the Trust's calculated distributable income was below the applicable subordination threshold. As a result, no distribution was paid for the subordinated units in each year. For the year ended December 31, 2017, no distribution was paid for the subordinated units during the year. The distributable income for the production periods from September 1, 2016 to May 31, 2017 was, in each case, below the applicable subordination threshold. The subordination threshold was not applicable to the distributable income for the production period from June 1, 2017 to August 31, 2017. The subordination and incentive thresholds terminated on June 30, 2017 and are no longer applicable for any future distribution. For more information, see Notes 1 and 6 to the financial statements contained in Part II, Item 8 of this Annual Report.

(4)

Royalty Income. Royalty income to the Trust for the year ended December 31, 2017, and attributable to the 2017 production period, totaled $15.7 million based upon sales of production attributable to the Royalty Interests of 134 mbbls of oil, 3,296 mmcf of natural gas and 332 mbbls of NGL. Total production attributable to the Royalty Interests for the 2017 production period was 1,015 mboe. Average prices received for oil, natural gas and NGL production, including the impact of certain post-production expenses and excluding production taxes, during the 2017 production period were $42.74 per bbl of oil, $0.99 per mcf of natural gas and $20.11 per bbl of NGL, respectively.

Royalty income to the Trust for the year ended December 31, 2016, and attributable to the 2016 production period, totaled $12.4 million based upon sales of production attributable to the Royalty Interests of 172 mbbls of oil, 4,306 mmcf of natural gas and 370 mbbls of NGL. Total production attributable to the Royalty Interests for the 2016 production period was 1,260 mboe. Average prices received for oil, natural gas and NGL production, including the impact of certain post-production expenses and excluding production taxes, during the 2016 production period were $34.28 per bbl of oil, $0.22 per mcf of natural gas and $15.08 per bbl of NGL, respectively.

Royalty income to the Trust for the year ended December 31, 2015, and attributable to the 2015 production period, totaled $36.4 million based upon sales of production attributable to the Royalty Interests of 269 mbbls of oil, 6,447 mmcf of natural gas and 575 mbbls of NGL. Total production attributable to the Royalty Interests for the 2015 production period was 1,920 mboe. Average prices received for oil, natural gas and NGL production, including the impact of certain post-production expenses and excluding production taxes, during the 2015 production period were $55.74 per bbl of oil, $1.65 per mcf of natural gas and $18.60 per bbl of NGL, respectively.

The increase in the price received per boe in the 2017 production period compared to the 2016 production period resulted in a $5.6 million increase in royalty income. Decreased sales volumes resulted in a $2.4 million decrease in royalty income, for a net increase in royalty income of $3.2 million.

The decrease in the price received per boe in the 2016 production period compared to the 2015 production period resulted in an $11.5 million decrease in royalty income. Decreased sales volumes resulted in a $12.5 million decrease in royalty income, for a net decrease in royalty income of $24.0 million.

Production Taxes. Production taxes are calculated as a percentage of oil, natural gas and NGL revenues, net of any applicable tax credits. Production taxes for the year ended December 31, 2017, and attributable to the 2017 production period, totaled $0.7 million, or $0.66 per boe, or approximately 4.3% of royalty income, as compared to production taxes of $0.4 million, or $0.36 per boe, or approximately 3.6% of royalty income for the year ended December 31, 2016, and attributable to the 2016 production period, and $0.7 million, or $0.35 per boe, or approximately 1.9% of royalty income, for the year ended December 31, 2015, and attributable to the 2015 production period. The increase in production taxes per boe from 2016 to 2017 was primarily due to an increase in oil, natural gas and NGL prices. The decrease in production taxes per boe from 2015 to 2016 was primarily due to a decrease in oil and natural gas prices.

Trust Administrative Expenses. Trust administrative expenses, including additional cash reserves, for the year ended December 31, 2017 totaled $1.7 million. Trust administrative expenses, including cash reserves, for the years ended December 31, 2016 and 2015 totaled $1.6 million and $1.5 million, respectively. Trust administrative expenses primarily consist of the administrative fees paid to the Trustees and Chesapeake and costs for accounting and legal services.

Cash Settlements on Derivatives. The Trust recorded gains or losses from the derivative contracts when proceeds were received or payments were made, respectively. There was no settlement of derivative contracts for the year ended December 31, 2017, as the Trust settled all derivative contracts as of February 2016. Swaps covering the 2015 production period were settled, during the year ended December 31, 2016, and proceeds received were included in the Trust's distributable income for the 2016 production period. Total gains on settlements of the derivative contracts during the year ended December 31, 2016 were $2.1 million. During the year ended December 31, 2015, swaps covering the 2015 production period were settled and proceeds received from the swap were included in the Trust's distributable net income for the 2015 production period. Total gains on settlements of the derivative contracts during the year ended December 31, 2015 were $19.1 million.

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, prior to the expiration of the derivative contracts on September 30, 2015, cash settlements on derivative contracts during periods in which oil prices fall below the fixed price received on derivative contracts. The Trust’s primary uses of cash are distributions to Trust unitholders, payments of production taxes, payments of Trust administrative expenses, including any reserves established by the Trustee for future liabilities and repayment of loans and payments of expense reimbursements to Chesapeake for out-of-pocket expenses incurred 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, natural gas and NGL 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.

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, 2017, four distributions were

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paid. The 2017 first quarter distribution of $.0912 per common unit to common unitholders consisting of proceeds attributable to production from September 1, 2016 through November 30, 2016, was made on March 2, 2017 to record unitholders as of February 20, 2017. The 2017 second quarter distribution of $0.1005 per common unit, consisting of proceeds attributable to production from December 1, 2016 through February 28, 2017, was made on June 1, 2017 to record unitholders as of May 22, 2017. The 2017 third quarter distribution of $0.1003 per common unit, consisting of proceeds attributable to production from March 1, 2017 through May 31, 2017, was made on August 31, 2017 to record unitholders as of August 21, 2017. The 2017 fourth quarter distribution of $0.0657 per common unit, consisting of proceeds attributable to production from June 1, 2017 through August 31, 2017, was made on November 30, 2017 to record unitholders as of November 20, 2017. As the distributable income per common unit for the 2017 first, second and third quarter distributions was below the applicable subordination threshold, no distribution was declared for the subordinated units.

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, 2017, 2016 and 2015 (in thousands except per unit amounts):

2017	Q1	Q2	Q3	Q4	Total
Distributable income	$3,197	$3,523	$3,518	$3,073	$13,311
Distributable income per common unit	$0.0912	$0.1005	$0.1003	$0.0657	$0.3577
Distributable income per subordinated unit[1]	$—	$—	$—	$—	$—

(1) On June 30, 2017, the subordinated units automatically converted into common units on a one-for-one basis. Distributions made on common units no longer have the benefit of the subordination threshold, nor are the common units subject to the incentive threshold, and all Trust unitholders share on a pro rata basis in the Trust's distribution.

2016	Q1	Q2	Q3	Q4	Total
Distributable income	$5,493	$1,412	$2,574	$3,006	$12,485
Distributable income per common unit[1]	$0.1567	$0.0403	$0.0734	$0.0857	$0.3561
Distributable income per subordinated unit	$—	$—	$—	$—	$—

(1) A distribution of $0.2195 per common unit was paid on March 1, 2016 to common unitholders of record, as of February 19, 2016, other than Chesapeake. Chesapeake received $0.0369 per common unit and waived its right to receive the higher distribution on its units with respect to the quarter ended December 31, 2015. The Trust's distributable income for the quarter ended December 31, 2015 was $0.1567 per common unit.

2015	Q1	Q2	Q3	Q4	Total
Distributable income	$15,763	$13,673	$12,548	$11,331	$53,315
Distributable income per common unit	$0.4496	$0.3899	$0.3579	$0.3232	$1.5206
Distributable income per subordinated unit	$—	$—	$—	$—	$—

On February 6, 2018, the Trust announced that a cash distribution of $0.0787 per common unit consisting of proceeds attributable to production from September 1, 2017 to November 30, 2017, to common unitholders of record, as of February 20, 2018 would be paid on March 2, 2018. See Note 7 to the financial statements contained in Part II, Item 8 of this Annual Report for additional information regarding the distribution paid on March 2, 2018 to record unitholders as of February 20, 2018.

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. As of December 31, 2017 and December 31, 2016, there were no loans outstanding.

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.

Contractual Obligations

As of December 31, 2017, the Trust had no obligations or commitments to make future contractual payments other than the Trustee administrative fee, administrative services fee and the Delaware Trustee administrative fee payable to the Trustee, Chesapeake and the Delaware Trustee, respectively. The table below summarizes the Trust's contractual obligations as of December 31, 2017.

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
	($ in thousands)				
Contractual Obligations:					
Trustee administrative fee	$2,417	$179	$358	$358	$1,522
Chesapeake administrative services fee	2,700	200	400	400	1,700
Delaware Trustee administrative fee	27	2	4	4	17
Total contractual obligations	$5,144	$381	$762	$762	$3,239

The Trust is obligated to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's expenses, approximately 60 days following the completion of each 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 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 SEC as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts. The Trust's financial statements for all periods presented 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 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 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, natural gas and NGL 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 outstanding derivatives. Actual results could differ from those estimates.

Derivatives. To mitigate a portion of the exposure to adverse market changes of oil prices, the Trust had derivative contracts covering a portion of oil production through September 30, 2015. See Note 3 to the financial statements contained in Part II, Item 8 of this Annual Report for further discussion of the derivative contracts.

The Trust recorded gains or losses from the derivative contracts when proceeds were received or payments were made, respectively. Additionally, changes in the fair value of the derivative contracts were 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 were increased or decreased by settlements of the Trust's derivative contracts. The Trust continued to settle derivative contracts through February 2016.

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

Oil, Natural Gas and NGL 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, natural gas and NGL from the Underlying Properties. The Trust is significantly exposed to fluctuations in the prices received for oil, natural gas and NGL produced and sold.

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, liquidity and ability to comply with the financial covenants contained in its debt instruments, which in turn will depend upon the supply and demand for oil, natural gas and NGL, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake’s control.

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

Opinion on the Financial Statements

We have audited the accompanying statements of assets, liabilities and trust corpus of the Chesapeake Granite Wash Trust (the "Trust") as of December 31, 2017 and 2016, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of the Trust as of December 31, 2017 and 2016, and its distributable income and its changes in trust corpus for each of the three years in the period ended December 31, 2017 in conformity with the modified cash basis of accounting described in Note 2.

Basis for Opinion

These financial statements are the responsibility of the Trust's management (the Trustee). Our responsibility is to express an opinion on the Trust's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Trust's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Basis of Accounting

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 accounting principles generally accepted in the United States of America.

/s/ PricewaterhouseCoopers LLP
Oklahoma City, Oklahoma

March 21, 2018

We have served as the Trust's auditor since 2011.

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

	December 31,	
	2017	2016
	($ in thousands)	
ASSETS:		
Cash and cash equivalents	$2,067	$1,215
Investment in royalty interests	487,793	487,793
Less: accumulated amortization	(461,488)	(457,070)
Net investment in royalty interests	26,305	30,723
Total assets	$28,372	$31,938
LIABILITIES AND TRUST CORPUS:		
Dividend Payable to Chesapeake[(1)]	$768	$—
Total liabilities	768	—
Trust Corpus; 46,750,000 common units issued and outstanding at December 31, 2017 and 35,062,500 common units and 11,687,500 subordinated units issued and outstanding December 31, 2016	27,604	31,938
Total liabilities and Trust corpus	$28,372	$31,938

(1) See Note 6 to the financial statements contained in Part II, Item 8 of this Annual Report.

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

CHESAPEAKE GRANITE WASH TRUST
STATEMENTS OF DISTRIBUTABLE INCOME

	Years Ended December 31,		
	2017	2016	2015
	($ in thousands, except per unit data)		
REVENUES:			
Royalty income	$15,665	$12,431	$36,377
INCOME (EXPENSES):			
Production taxes	(669)	(449)	(681)
Trust administrative expenses	(1,685)	(1,606)	(1,466)
Derivative settlement gain	—	2,109	19,085
Total income (expenses)	(2,354)	54	16,938
Distributable income available to unitholders	$13,311	$12,485	$53,315
Distributable income per common unit (46,750,000 common units at December 31, 2017 and 35,062,500 common units at December 31, 2016 and December 31, 2015)	$0.3577	$0.3561	$1.5206
Distributable income per subordinated unit (0 subordinated units at December 31, 2017 and 11,687,500 subordinated units at December 31, 2016 and December 31, 2015)	$—	$—	$—

CHESAPEAKE GRANITE WASH TRUST
STATEMENTS OF CHANGES IN TRUST CORPUS

	Years Ended December 31,		
	2017	2016	2015
	($ in thousands)		
TRUST CORPUS: Beginning of period	$31,938	$63,216	$256,604
Cash reserve surplus (deficit)[1]	(683)	242	(133)
Amortization of investment in royalty interests	(4,419)	(6,802)	(22,536)
Impairment of investment in royalty interests	—	(22,609)	(154,206)
Change in derivative asset/liability	—	(2,109)	(16,513)
Distributable income	13,311	12,485	53,315
Distributions paid to unitholders[1]	(12,543)	(12,485)	(53,315)
TRUST CORPUS: End of period	$27,604	$31,938	$63,216

(1) See Note 6 to the financial statements contained in Part II, Item 8 of this Annual Report.

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

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 drilled on properties held by Chesapeake within the AMI. Pursuant to a development agreement with the Trust, Chesapeake was 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 was 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 96% of the Producing Wells and the completed Development Wells. As of June 30, 2016, Chesapeake had fulfilled its drilling obligation under the development agreement.

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. 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, natural gas and NGL 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, natural gas and NGL 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.

Prior to their conversion on June 30, 2017, the subordinated units were entitled to receive pro rata distributions from the Trust each quarter if and to the extent there was sufficient cash to provide a cash distribution on the common units that was no less than 80% of the target distribution set forth in the Trust Agreement for the corresponding quarter (the “subordination threshold”). If there was insufficient cash to fund such a distribution on all of the Trust units, the distribution made with respect to the subordinated units was either 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. Prior to the conversion of the subordinated units on June 30, 2017, Chesapeake was 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 was 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, if any, was to be paid to Trust unitholders, including Chesapeake, on a pro rata basis.

On June 30, 2017, the last day of the fourth full calendar quarter subsequent to Chesapeake's satisfaction of its drilling obligation under the development agreement, the subordinated units automatically converted into common units on a one-for-one basis and Chesapeake's right to receive incentive distributions with respect to quarters after the 2017 second quarter terminated. All distributions made on common units after September 30, 2017 no longer have

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

the benefit of the subordination threshold, nor are the common units subject to the incentive threshold, and all Trust unitholders share on a pro rata basis in the Trust's distributions.

The distribution for the quarter ended June 30, 2017 which was paid on August 31, 2017, was still subject to the subordination threshold. As a result, distributable income available to unitholders for the three and nine months ended September 30, 2017 was still subject to the subordination threshold. As such, distributable income per common unit as of September 30, 2017 was based upon 35,062,500 common units (see Note 6). Beginning with the November 30, 2017 distribution, the distributable income available to unitholders is based on the 46,750,000 common units that are currently outstanding (see Note 7).

The aggregate distributions paid in the year ended December 31, 2017 were $0.3577 per common unit. No subordinated unit distributions were paid during the year ended December 31, 2017. The distributable income for the production periods from September 1, 2016 to May 31, 2017 was, in each case, below the applicable subordination threshold. The subordination threshold was not applicable to the distributable income for the production period from June 1, 2017 to August 31, 2017. See Note 6 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 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, natural gas and NGL 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 outstanding 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, natural gas and NGL, 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, natural gas and NGL prices historically have been volatile and may be subject to significant fluctuations in the future. The Trust’s derivative contracts, which were only in effect through September 30, 2015, served to mitigate the effect of this price volatility on a portion of the Trust’s anticipated oil and NGL production. Beginning October 1, 2015, all of the production attributable to the Trust's Royalty Interests is subject to market prices, and currently, there are no derivative contracts. See Note 3 for a discussion of the Trust’s former derivative contracts.

The Trust’s income available for distribution throughout 2016 and 2017 has been adversely affected by several factors. The Trust's revenues and distributable income available to unitholders have been and will continue to be adversely affected if commodity prices or production remain at current levels or decline further. For the quarterly production periods from September 1, 2016 to May 31, 2017, the Trust paid a common unit distribution below the

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

applicable subordination threshold and no subordinated distribution was paid. The subordination threshold was not applicable to the distributable income for the quarterly production period from June 1, 2017 to August 31, 2017. On February 6, 2018, the Trust declared a cash distribution of $0.0787 per common unit, consisting of proceeds attributable to production from September 1, 2017 to November 30, 2017. The distribution was paid on March 2, 2018 to record unitholders as of February 20, 2018. See Note 6 for information regarding prior distributions paid and Note 7 for information regarding the distribution paid on March 2, 2018.

During the year ended December 31, 2017, none of the distributable income available to common unitholders was attributable to derivative settlement gains. As disclosed in Note 3, the derivative contracts were initially novated to the Trust in November 2011 and covered a portion of the production attributable to the Royalty Interests from October 1, 2011 through September 30, 2015. Settlement of these derivative contracts continued through February 2016.

During the year ended December 31, 2017, the Trust recognized no impairments of the Royalty Interests. During the years ended December 31, 2016 and 2015, the Trust recognized approximately $22.6 million and $154.2 million, respectively, in impairments of the Royalty Interests. See Investment in Royalty Interests below for further discussion of the impairments.

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, natural gas and NGL, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake’s control.

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 and Cash Equivalents. 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 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 rules of 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. During the year ended December 31, 2017 there were no impairments to the carrying value of the Investment in Royalty Interests. During the years ended December 31, 2016 and 2015, there was an aggregate of $22.6 million, and $154.2 million, respectively, in impairments to the carrying value of the Investment in Royalty Interests. The 2016 impairments were primarily due to a decrease in commodity prices used to calculate the proved reserves attributable to the Trust's interest in the Underlying Properties. The impairments resulted in non-cash charges to Trust corpus and did not affect the Trust's distributable income. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters. See Risks and Uncertainties above for further discussion.

Derivatives. To mitigate a portion of the exposure to adverse market changes of oil prices, the Trust had derivative contracts covering a portion of oil production through September 30, 2015. See Note 3 for discussion of the derivative contracts.

The Trust recorded gains or losses from the derivative contracts when proceeds were received or payments were made, respectively. Additionally, changes in the fair value of the derivative contracts were 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 were increased or decreased by settlements of the Trust's derivative contracts. The Trust continued to settle the derivative contracts through February 2016.

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

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 and unless Chesapeake agrees otherwise) until the loan is repaid. There were no loans outstanding as of December 31, 2017 or December 31, 2016.

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, natural gas and NGL 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.

3. Derivative Contracts

The Trust's derivative contracts were intended to manage its exposure to adverse changes in oil prices. On November 16, 2011, Chesapeake novated derivative contracts 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 consisted of fixed-price oil swaps in which the Trust received a fixed price and paid 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 received payments directly from its counterparty or was required to pay any amounts owed directly to the counterparty. All swaps were net settled based on the difference between the fixed-price payment and the floating-price payment. All of the Trust's derivative contracts expired on September 30, 2015 and as of February 2016, the Trust had settled all derivative contracts. The Trust settled derivative contracts that resulted in receipts from the counterparty of $2.1 million for the year ended December 31, 2016 and $19.1 million for the year ended December 31, 2015, respectively.

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. As of December 31, 2017, a 2.1% inflation adjustment has been made for the 2017 calendar year.

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 $218,000, $168,000 and $247,000 in fees and reimbursements in 2017, 2016 and 2015, respectively. Additionally, the administrative services agreement established Chesapeake as the Trust's hedge manager, pursuant to which Chesapeake had the authority, on behalf of the Trust, to administer the Trust's derivative contracts. All of the Trust's derivative contracts expired on September 30, 2015.

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 upon by Chesapeake and the Trustee.

Pursuant to the development agreement with the Trust, Chesapeake was 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 was obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake 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 met its obligation to drill the Development Wells. As of June 30, 2016, Chesapeake had fulfilled its drilling obligation under the development agreement.

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 insufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will loan

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

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, 2017 or December 31, 2016.

6. 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.

For the years ended December 31, 2017, 2016 and 2015, the Trust declared and paid the following cash distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit		Cash Distribution per Subordinated Unit[1]
		Public Unitholders Other Than Chesapeake	Chesapeake	
June 2017 – August 2017[2]	November 30, 2017	$0.0657	$ 0.0657	$ —
March 2017 – May 2017[3]	August 31, 2017	$0.1003	$ 0.1003	$ —
December 2016 – February 2017	June 1, 2017	$0.1005	$ 0.1005	$ —
September 2016 – November 2016	March 2, 2017	$0.0912	$ 0.0912	$ —
June 2016 – August 2016	December 1, 2016	$0.0857	$ 0.0857	$ —
March 2016 – May 2016	August 29, 2016	$0.0734	$ 0.0734	$ —
December 2015 – February 2016	May 31, 2016	$0.0403	$ 0.0403	$ —
September 2015 – November 2015[4]	March 1, 2016	$0.2195	$ 0.0369	$ —
June 2015 – August 2015	November 30, 2015	$0.3232	$ 0.3232	$ —
March 2015 – May 2015	August 31, 2015	$0.3579	$ 0.3579	$ —
December 2014 – February 2015	June 1, 2015	$0.3899	$ 0.3899	$ —
September 2014 – November 2014	March 2, 2015	$0.4496	$ 0.4496	$ —

(1)

For the production periods from June 2013 through February 2017, the distribution per common unit was below the applicable subordination threshold, and no distribution was declared for the subordinated units. On June 30, 2017, the subordinated units automatically converted into common units on a one-for-one basis. Distributions made on common units no longer have the benefit of the subordination threshold, nor are the common units subject to the incentive threshold, and all Trust unitholders share on a pro rata basis in the Trust's distribution.

(2) The Trust inadvertently failed to pay Chesapeake its quarterly distribution on November 30, 2017 with respect to Chesapeake's common units that converted from subordinated units on June 30, 2017. As a result, the unpaid balance as of December 31, 2017 is reflected as “Dividend Payable to Chesapeake” on the Statement of Assets, Liabilities and Trust Corpus as of December 31, 2017. The unpaid distribution was paid in full in February 2018. Distributions paid to Trust unitholders and distributions paid to Chesapeake with respect to its common units for such period were calculated pursuant to the Trust Agreement.

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

(3) Following the Trust's press release dated August 4, 2017, the Trust identified an additional $190,000 to be included in distributable income available to unitholders. The Trust announced a revision to the distribution amount on August 11, 2017. Based upon the revised sales volume and average pricing calculations, the distribution of $0.1003 per common unit, which was calculated on the basis of 35,062,500 common units and excluded the common units issued on June 30, 2017 upon conversion of the Trust's subordinated units, was paid on August 31, 2017.

(4) In its press release dated February 4, 2016, the Trust incorrectly announced that the distributable income for the quarter ended December 31, 2015 was $0.2195 per common unit. Chesapeake advised the Trust that Chesapeake included an incorrect amount for the derivative settlement gain in the prior calculation of distributable income. Chesapeake elected to waive its right to the higher distribution on common units held by Chesapeake with respect to the 2016 first quarter distribution. As a result, Chesapeake's distribution was reduced by approximately $1.4 million to allow all other common unitholders to receive a distribution of $0.2195 per common unit as previously announced. Chesapeake received a distribution of $0.0369 per common unit.

7. Subsequent Events

The Trust's quarterly income available for distribution was $0.0787 per common unit for the production period from September 1, 2017 to November 30, 2017. On February 6, 2018, the Trust declared a cash distribution of $0.0787 per common unit attributable to such production period. The distribution was paid on March 2, 2018 to record unitholders as of February 20, 2018. All Trust unit holders share on a pro rata basis in the Trust's distributable income.

Distributable income attributable to production from September 1, 2017 to November 30, 2017, was calculated as follows (in thousands except for unit and per unit amounts):

Revenues:	
Royalty income[1]	$3,925
Income (Expenses):	
Production taxes	(243)
Trust administrative expenses[2]	(2)
Total expenses	(245)
Distributable income available to unitholders	$3,680
Distributable income per common unit (46,750,000 units)	$0.0787

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

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION

Quarterly Financial Data (unaudited)

The following is a summary of royalty income and distributable income by quarter for 2017 and 2016:

	Year Ended December 31, 2017				
	Q1	Q2	Q3	Q4	2017
	($ in thousands, except per unit data)				
Royalty income	$3,773	$4,533	$3,939	$3,420	$15,665
Distributable income	$3,197	$3,523	$3,518	$3,073	$13,311
Distributable income per common unit	$0.0912	$0.1005	$0.1003	$0.0657	$0.3577
Distributable income per subordinated unit[(1)]	$—	$—	$—	$—	$—

(1) On June 30, 2017, the subordinated units automatically converted into common units on a one-for-one basis. Distributions made on common units no longer have the benefit of the subordination threshold, nor are the common units subject to the incentive threshold, and all Trust unitholders share on a pro rata basis in the Trust's distribution.

	Year Ended December 31, 2016				
	Q1	Q2	Q3	Q4	2016
	($ in thousands, except per unit data)				
Royalty income	$4,079	$2,354	$2,608	$3,390	$12,431
Distributable income	$5,493	$1,412	$2,574	$3,006	$12,485
Distributable income per common unit[(1)]	$0.1567	$0.0403	$0.0734	$0.0857	$0.3561
Distributable income per subordinated unit	$—	$—	$—	$—	$—

(1) A distribution of $0.2195 per common unit was paid on March 1, 2016 to common unitholders of record, as of February 19, 2016, other than Chesapeake. Chesapeake received $0.0369 per common unit and waived its right to receive the higher distribution on its units with respect to the quarter ended December 31, 2015. The Trust's distributable income for the quarter ended December 31, 2015 was $0.1567 per common unit.

Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities (unaudited)

Net Capitalized Costs. Capitalized costs related to the Trust's oil, natural gas and NGL producing activities are summarized as follows:

	December 31,	
	2017	2016
	($ in thousands)	
Oil and natural gas properties:		
Proved	$487,793	$487,793
Unproved	—	—
Total	487,793	487,793
Less accumulated amortization	(461,488)	(457,070)
Net capitalized costs	$26,305	$30,723

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, Natural Gas and NGL Producing Activities. Chesapeake's results of operations from oil, natural gas and NGL producing activities for the Trust's interest are presented below for the years ended December 31, 2017, 2016 and 2015. 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:

	Years Ended December 31,		
	2017	2016	2015
	($ in thousands)		
Sales of oil, natural gas and NGL	$15,665	$12,431	$36,377
Production taxes	(669)	(449)	(681)
Amortization of investment in royalty interests	(4,419)	(6,802)	(22,536)
Impairment of investment in royalty interests	—	(22,609)	(154,206)
Results of operations from oil, natural gas and NGL producing activities	$10,577	$(17,429)	$(141,046)

The following oil, natural gas and NGL 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, 2017 is as follows:

Year Ended December 31, 2017	Modified Cash Basis[1]	For the Period Ended September 1, 2016 to December 31, 2016	September 1, 2017 to December 31, 2017	Accrual Basis[2]
Production Data:				
Oil (mbbl)	134	(47)	31	118
Natural Gas (mmcf)	3,296	(1,189)	903	3,010
NGL (mbbl)	332	(108)	92	316
Total (mboe)	1,015	(353)	274	936
Royalty income (in thousands)	$15,665	$(18,146)	$17,304	$14,823
Production taxes (in thousands)	(669)	228	(437)	(878)
	$14,996	$(17,918)	$16,867	$13,945

(1) Oil, natural gas and NGL volumes attributable to the Royalty Interests and related revenues and expenses included in Chesapeake's 2016 net revenue distributions to the Trust. Represents oil, natural gas and NGL production from September 1, 2016 to August 31, 2017.

(2) Oil, natural gas and NGL volumes attributable to the Royalty Interests and related revenues and expenses, presented on an accrual basis, from January 1, 2017 through December 31, 2017, 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, 2016 is as follows:

Year Ended December 31, 2016	Modified Cash Basis[1]	For the Period Ended September 1, 2015 to December 31, 2015	September 1, 2016 to December 31, 2016	Accrual Basis[2]
Production Data:				
Oil (mbbl)	172	(58)	47	161
Natural Gas (mmcf)	4,306	(1,634)	1,189	3,861
NGL (mbbl)	370	(127)	108	351
Total (mboe)	1,260	(458)	353	1,155
Royalty income (in thousands)	$12,431	$(17,352)	$ 18,146	$13,225
Production taxes (in thousands)	(449)	133	(228)	(544)
	$11,982	$(17,219)	$ 17,918	$12,681

(1) Oil, natural gas and NGL volumes attributable to the Royalty Interests and related revenues and expenses included in Chesapeake's 2016 net revenue distributions to the Trust. Represents oil, natural gas and NGL production from September 1, 2015 to August 31, 2016.

(2) Oil, natural gas and NGL volumes attributable to the Royalty Interests and related revenues and expenses, presented on an accrual basis, from January 1, 2016 through December 31, 2016, 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 year ended December 31, 2015 is as follows:

Year Ended December 31, 2015	Modified Cash Basis[1]	For the Period Ended September 1, 2014 to December 31, 2014	September 1, 2015 to December 31, 2015	Accrual Basis[2]
Production Data:				
Oil (mbbl)	269	(93)	58	234
Natural Gas (mmcf)	6,447	(2,474)	1,634	5,607
NGL (mbbl)	575	(253)	127	449
Total (mboe)	1,920	(760)	548	1,618
Royalty income (in thousands)	$36,377	$(18,472)	$ 17,352	$35,257
Production taxes (in thousands)	(681)	386	(133)	(428)
	$35,696	$(18,086)	$ 17,219	$34,829

(1) Oil, natural gas and NGL volumes attributable to the Royalty Interests and related revenues and expenses included in Chesapeake's 2015 net revenue distributions to the Trust. Represents oil, natural gas and NGL production from September 1, 2014 to August 31, 2015.

(2) Oil, natural gas and NGL volumes attributable to the Royalty Interests and related revenues and expenses, presented on an accrual basis, from January 1, 2015 through December 31, 2015, a portion of which will be reflected on the modified cash basis in distributable income in subsequent quarters.

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CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION – (Continued)

Estimated Oil, Natural Gas and NGL Reserve Quantities. The Trust's independent petroleum engineering firm, Software Integrated Solutions, Division of Schlumberger Technology Corporation, estimated all of the proved reserves as of December 31, 2017 for the Royalty Interests. The qualifications of the technical person at Software Integrated Solutions primarily responsible for overseeing the 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 geologist licensed in the Commonwealth of Pennsylvania;
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and
- Bachelor of Science degree in Geological Sciences.

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

Developed oil, natural gas and NGL 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, natural gas and NGL 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 2017, 2016 and 2015.

	December 31, 2017			
	Oil (mbbl)	Gas (mmcf)	NGL (mbbl)	Total (mboe)
Proved reserves, beginning of period	686	23,296	2,033	6,601
Extensions, discoveries and other additions	—	—	—	—
Revisions of previous estimates, price[1]	58	1,860	166	533
Revisions of previous estimates, other[2]	(22)	(2,489)	175	(260)
Production	(118)	(3,010)	(316)	(936)
Proved reserves, end of period	604	19,657	2,058	5,938
Proved developed reserves:				
Beginning of period	686	23,296	2,033	6,601
End of period	604	19,657	2,058	5,938
Proved undeveloped reserves:				
Beginning of period	—	—	—	—
End of period	—	—	—	—

	December 31, 2016			
	Oil (mbbl)	Gas (mmcf)	NGL (mbbl)	Total (mboe)
Proved reserves, beginning of period	896	32,237	3,233	9,502
Extensions, discoveries and other additions	—	—	—	—
Revisions of previous estimates, price[3]	(29)	(920)	(95)	(277)
Revisions of previous estimates, other[4]	(20)	(4,160)	(754)	(1,469)
Production	(161)	(3,861)	(351)	(1,155)
Proved reserves, end of period	686	23,296	2,033	6,601
Proved developed reserves:				
Beginning of period	840	30,004	3,039	8,880
End of period	686	23,296	2,033	6,601
Proved undeveloped reserves:				
Beginning of period	56	2,233	194	622
End of period	—	—	—	—

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION – (Continued)

	December 31, 2015			
	Oil (mbbl)	Gas (mmcf)	NGL (mbbl)	Total (mboe)
Proved reserves, beginning of period	1,468	45,510	4,870	13,923
Extensions, discoveries and other additions[5]	132	3,646	316	1,056
Revisions of previous estimates, price[6]	(113)	(3,301)	(358)	(1,022)
Revisions of previous estimates, other[7]	(357)	(8,011)	(1,146)	(2,837)
Production	(234)	(5,607)	(449)	(1,618)
Proved reserves, end of period	896	32,237	3,233	9,502
Proved developed reserves:				
Beginning of period	1,076	36,135	3,874	10,972
End of period	840	30,004	3,039	8,880
Proved undeveloped reserves:				
Beginning of period	392	9,375	996	2,951
End of period	56	2,233	194	622

(1) During 2017, the Trust recorded upward reserve revisions of 533 mboe to the December 31, 2016 estimates of reserves resulting from changes to oil and natural gas prices. Before basis differential adjustments, oil and natural gas prices used in estimating proved reserves increased as of December 31, 2017 compared to December 31, 2016 using the trailing 12-month average prices required by the SEC. Oil prices increased by $8.59 per bbl, or 20%, to $51.34 per bbl from $42.75 per bbl. Natural gas prices increased $0.49 per mcf, or 20%, to $2.98 per mcf from $2.49 per mcf.

(2) During 2017, the Trust recorded downward reserve revisions of 260 mboe to the December 31, 2016 estimates of reserves resulting from changes to previous estimates. These non-price related revisions were primarily attributable to lower production in forecasts.

(3) During 2016, the Trust recorded downward reserve revisions of 277 mboe to the December 31, 2015 estimates of reserves resulting from changes to oil and natural gas prices. Before basis differential adjustments, oil and natural gas prices used in estimating proved reserves decreased substantially as of December 31, 2016 compared to December 31, 2015 using the trailing 12-month average prices required by the SEC. Oil prices decreased by $7.53 per bbl, or 15%, to $42.75 per bbl from $50.28 per bbl. Natural gas prices decreased $0.09 per mcf, or 3%, to $2.49 per mcf from $2.58 per mcf.

(4) During 2016, the Trust recorded downward reserve revisions of 1,469 mboe to the December 31, 2015 estimates of reserves resulting from changes to previous estimates. These non-price related revisions were primarily attributable to shut-in wells and lower production in forecasts.

(5) During 2015, the Trust recorded 1,056 mboe of extensions, discoveries, and other additions. New PUDs were added because the drilling locations were changed, and these extensions were partially offset with the removal of PUDs shown in the revisions of previous estimates.

(6) During 2015, the Trust recorded downward reserve revisions of 1,022 mboe to the December 31, 2014 estimates of reserves resulting from changes to oil and natural gas prices. Before basis differential adjustments, oil and natural gas prices used in estimating proved reserves decreased substantially as of December 31, 2015 compared to December 31, 2014 using the trailing 12-month average prices required by the SEC. Oil prices decreased by $44.70 per bbl, or 47%, to $50.28 per bbl from $94.98 per bbl. Natural gas prices decreased $1.77 per mcf, or 41%, to $2.58 per mcf from $4.35 per mcf.

(7)

During 2015, the Trust recorded downward reserve revisions of 2,837 mboe to the December 31, 2014 estimates of reserves resulting from changes to previous estimates. These non-price related revisions were primarily due to the removal of PUDs that are not part of Chesapeake's drilling plan within the AMI. As a result of substantially

CHESAPEAKE GRANITE WASH TRUST
SUPPLEMENTARY INFORMATION – (Continued)

lower oil and natural gas prices, Chesapeake reduced its operated rig count in the AMI in February 2015 from two rigs to one rig to slow the pace of its drilling program.

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, 2017, 2016 and 2015. As of December 31, 2017, 2016 and 2015 the Trust had not received royalty income associated with the production sold from each of the production periods from September 1 – December 31, 2017, September 1 – December 31, 2016 and September 1 – December 31, 2015, respectively.

	December 31, 2017			
	Oil (mbbl)	Gas (mmcf)	NGL (mbbl)	Total (mboe)
Proved reserves, accrual basis	604	19,657	2,058	5,938
Production September 1 – December 31, 2017	31	903	92	274
Adjusted Proved reserves, on a modified cash basis	635	20,560	2,150	6,212
	December 31, 2016			
	Oil (mbbl)	Gas (mmcf)	NGL (mbbl)	Total (mboe)
Proved reserves, accrual basis	686	23,296	2,033	6,601
Production September 1 – December 31, 2016	47	1,189	108	353
Adjusted Proved reserves, on a modified cash basis	733	24,485	2,141	6,954
	December 31, 2015			
	Oil (mbbl)	Gas (mmcf)	NGL (mbbl)	Total (mboe)
Proved reserves, accrual basis	896	32,237	3,233	9,502
Production September 1 – December 31, 2015	58	1,634	127	458
Adjusted Proved reserves, on a modified cash basis	954	33,871	3,360	9,960

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, 2017, 2016 and 2015 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, natural gas and NGL 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 that 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, natural gas and NGL reserves based on the standardized measure:

	Years Ended December 31,		
	2017	2016	2015
	($ in thousands)		
Future cash inflows	$82,305 (1)	$61,647 (2)	$103,610 (3)
Future production costs(4)	(5,923)	(4,261)	(6,435)
Future development costs(5)	—	—	—
Future income tax provisions(6)	—	—	—
Future net cash flows	76,382	57,386	97,175
Less effect of a 10% discount factor	(31,765)	(22,901)	(37,052)
Standardized measure of discounted future net cash flows	$44,617	$34,485	$60,123

(1) Calculated using prices of $2.98 per mcf of natural gas and $51.34 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, 2017 were $0.39 per mcf of natural gas, $46.64 per barrel of oil and $22.61 per barrel of NGL.

(2) Calculated using prices of $2.49 per mcf of natural gas and $42.75 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, 2016 were $0.15 per mcf of natural gas, $36.02 per barrel of oil and $16.42 per barrel of NGL.

(3) Calculated using prices of $2.58 per mcf of natural gas and $50.28 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, 2015 were $0.66 per mcf of natural gas, $43.82 per barrel of oil and $13.32 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.

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following schedule reconciles the changes for the years ended December 31, 2017, 2016 and 2015 in the standardized measure of discounted future net cash flows relating to proved reserves:

	Years Ended December 31,		
	2017	2016	2015
	($ in thousands)		
Standardized measure, beginning of period	$34,485	$60,123	$236,875
Sales of oil and gas produced, net of production costs	(13,945)	(12,681)	(34,829)
Net changes in prices and production costs	17,645	(6,980)	(136,229)
Extensions and discoveries, net of production and development costs	—	—	8,754
Revision of previous quantity estimates	2,108	(9,393)	(23,887)
Accretion of discount	3,449	6,012	23,687
Production timing and other	875	(2,596)	(14,248)
Standardized measure, end of period	$44,617	$34,485	$60,123

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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 Trust's disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), are designed to ensure that the 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 Chesapeake to The Bank of New York Mellon Trust Company, N.A., as the 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 disclosure.

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 (a) the Trust Agreement, (b) the administrative services agreement, (c) the development agreement and (d) the conveyances granting the Royalty Interests, the Trust's disclosure controls and procedures necessarily rely on (i) 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 (ii) conclusions and reports regarding reserves by the Trust's independent reserve engineers. Although the Trustee does rely on Chesapeake to perform certain functions and to provide certain information that impact the Trust's financial statements, the Trustee remains responsible for evaluating, as appropriate, the Trust's disclosure controls and procedures as well as its internal control over financial reporting.

The Vice President of the Trustee has evaluated the effectiveness of the Trust's disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this Annual Report. Based on her evaluation, as of December 31, 2017, she has concluded that the Trust's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) were effective.

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). 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 the modified cash basis of accounting, which is a comprehensive basis of accounting other than generally accepted accounting principles.

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 risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

As of December 31, 2017, the Trustee assessed the effectiveness of the Trust's internal control over financial reporting based on the criteria described in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that assessment, the Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2017 based on those criteria.

Remediation of Prior Material Weakness.

As disclosed in our Annual Report on Form 10-K for the year ended December 31, 2016, the Trustee previously identified a material weakness related to the valuation of proved oil and natural gas properties and the accuracy of impairment of oil and natural gas properties. Specifically, the review of the initial configuration of a newly implemented tool used to calculate basis price differentials did not detect an error in the calculation formula and the manual interface control that compared the data used in the tool to the general ledger was not designed at an

appropriately disaggregated level.

The Trust has taken the necessary steps to enhance the underlying control activities, which now include restricted access within the tool to maintain and control changes to the formulaic calculations, a manual interface control to validate that the automated interface configuration and calculation formulas are accurate, and a manual recalculation of the basis price differentials.

Based on the results of the Trust's evaluation, the Trustee has concluded that the controls are designed and operating effectively as of December 31, 2017 and, therefore, the previously disclosed material weakness has been remediated.

Changes in Internal Control over Financial Reporting.

Except as set forth above, there were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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 2017. 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 year ended December 31, 2017, the Trustee received an administrative fee of $178,675 from the Trust and during the years ended December 31, 2016 and 2015, the Trustee received an administrative fee of $175,000 from the Trust. 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)]	23,750,000 Common Units	50.8%

(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 reported in the table above. Chesapeake may be deemed to beneficially own the common 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 Sarika Jewell that exercises voting and investment control with respect to Chesapeake's common 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 of December 31, 2017, a 2.1% inflation adjustment had been made for the 2017 calendar year. As the Trust uses the modified cash basis of accounting, general and administrative expenses in the Trust's statements of distributable income for the year ended December 31, 2017 include $178,675 for administrative fees paid to the Trustee and for the years ended December 31, 2016 and 2015 include $175,000 for administrative fees paid to the Trustee.

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.

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 upon 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 obligated 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 was obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake 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 met its obligation to drill the Development Wells. As of June 30, 2016, Chesapeake had fulfilled its drilling obligation under the development agreement.

In drilling the Development Wells, Chesapeake was required to adhere to the Reasonably Prudent Operator Standard. Where Chesapeake did not operate the Underlying Properties, Chesapeake was 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.

Following the drilling of each Development Well, Chesapeake was obligated to attempt to complete each such well that reasonably appeared 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 was 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 was unable to successfully complete a Development Well, Chesapeake was obligated to plug and abandon such well to the extent required by law.

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

ITEM 14. Principal Accountant Fees and Services

Estimated fees for services performed by PricewaterhouseCoopers L.L.P. for the years ended December 31, 2017 and 2016, are as follows:

	Years Ended December 31,	
	2017	2016
Audit Fees[1]	$310,000	$227,000
Audit-Related Fees	—	—
Tax Fees	353,021	363,758
Total	$663,021	$590,758

(1) Fees for audit services in 2017 and 2016 include fees for the reviews of the Trust's quarterly financial statements.

As a modified cash basis entity, the Trust expenses 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 financial statements, financial statement schedules and exhibits are filed as a part of this report:

1. Financial Statements. Chesapeake Granite Wash Trust's financial statements are included in Item 8 of Part II of this report.
2. Financial Statement Schedules. No financial statement schedules are applicable or required.
3. Exhibits. The exhibits listed below in the Index of Exhibits are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

INDEX OF EXHIBITS

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith or Furnished
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, 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, L.L.C. and Chesapeake E&P Holding Corporation.	8-K	001-35343	10.4	11/21/2011	
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	

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith or Furnished
		Form	SEC File Number	Exhibit	Filing Date	
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	
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	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	
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 Software Integrated Solutions, Division of Schlumberger Technology Corporation.					X

ITEM 16. Form 10-K Summary

None.

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 21, 2018

CHESAPEAKE GRANITE WASH TRUST

By: THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., Trustee

By: /s/ Sarah C. Newell
Sarah C. Newell
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.