

CHESAPEAKE GRANITE WASH TRUST  
Form 10-Q  
November 14, 2012  
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UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION  
Washington, D.C. 20549  
FORM 10-Q

Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934  
For the Quarterly Period Ended September 30, 2012

Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934  
For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File No. 001-35343

Chesapeake Granite Wash Trust  
(Exact name of registrant as specified in its charter)

Delaware

45-6355635

(State or other jurisdiction of incorporation or  
organization)

(I.R.S. Employer Identification No.)

The Bank of New York Mellon  
Trust Company, N.A., Trustee

Global Corporate Trust

919 Congress Avenue

Austin, Texas

78701

(Address of principal executive offices)

(Zip Code)

(855) 802-1093

(Registrant's telephone number, including area code)

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  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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer  Accelerated filer  Non-accelerated filer  Smaller reporting company

(Do not check if a smaller  
reporting company)

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

As of November 13, 2012, 35,062,500 Common Units and 11,687,500 Subordinated Units representing beneficial interests in Chesapeake Granite Wash Trust were outstanding.

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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.

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**DISCLOSURES REGARDING FORWARD-LOOKING STATEMENTS**

This Quarterly Report on Form 10-Q (“Quarterly Report”) includes “forward-looking statements” about the Trust and Chesapeake and other matters discussed herein that are subject to risks and uncertainties that are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this document, including, without limitation, statements under “Trustee’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 2 of Part I and “Risk Factors” in Item 1A of Part II and elsewhere herein regarding the proved oil and natural gas reserves associated with the properties underlying the Royalty Interests, the Trust’s or Chesapeake’s future financial position, business strategy, budgets, projected costs and plans and objectives for future operations, information regarding target distributions, statements pertaining to future development activities and costs, statements regarding the number of development wells to be completed in future periods and information regarding production and reserve growth, are forward-looking statements. Actual outcomes and results may differ materially from those projected. Our forward-looking statements are generally accompanied by words such as “estimate,” “project,” “predict,” “believe,” “expect,” “anticipate,” “potential,” “could,” “may,” “foresee,” “plan,” “goal,” “assume,” “intend” or other words that convey the uncertainty of future events or outcomes. These statements are based on certain assumptions made by the Trust, and by Chesapeake in light of its experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate under the circumstances. However, whether actual results and developments will conform with such expectations and predictions is subject to a number of risks and uncertainties, including the risk factors discussed in Item 1A of Part I of the Trust’s Annual Report on Form 10-K for the year ended December 31, 2011, and those set forth from time to time in the Trust’s filings with the Securities and Exchange Commission, which could affect the energy industry in general, and the Trust and Chesapeake in particular, and could cause those future results to differ materially from those expressed in such forward-looking statements. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to or effects on Chesapeake’s business and the Trust. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in such forward-looking statements. The Trustee relies on Chesapeake for information regarding the Royalty Interests, the Underlying Properties and Chesapeake itself. The Trust undertakes no obligation to publicly update or revise any forward-looking statements.

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## PART I. FINANCIAL INFORMATION

## ITEM 1. Financial Statements

## CHESAPEAKE GRANITE WASH TRUST

## STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

(\$ in thousands)

(Unaudited)

	September 30, 2012	December 31, 2011
<b>ASSETS:</b>		
Cash and cash equivalents	\$1,147	\$1,216
Investment in royalty interest	487,793	487,793
Less: accumulated amortization	(43,985	) (5,350
Net investment in royalty interest	443,808	482,443
Total assets	\$444,955	\$483,659
<b>LIABILITIES AND TRUST CORPUS:</b>		
Loan from Chesapeake	\$—	\$200
Short-term derivative liability	3,951	7,604
Total short-term liabilities	3,951	7,804
Long-term derivative liability	5,030	12,937
Trust corpus; 35,062,500 common units and 11,687,500 subordinated units authorized and outstanding	435,974	462,918
Total liabilities and trust corpus	\$444,955	\$483,659

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

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STATEMENTS OF DISTRIBUTABLE INCOME

(\$ in thousands, except per unit data)

(Unaudited)

	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
REVENUES:		
Royalty income	\$30,955	\$101,579
Interest income	1	3
Total Revenues	30,956	101,582
EXPENSES:		
Production taxes	797	2,347
Trust administrative expenses	445	1,250
Derivative settlement loss	2,623	6,014
Cash reserves withheld	71	131
Total Expenses	3,936	9,742
Distributable income	\$27,020	\$91,840
Distributable income per common unit (35,062,500 units)	\$0.6100	\$1.9965
Distributable income per subordinated unit (11,687,500 units)	\$0.4819	\$1.8684

CHESAPEAKE GRANITE WASH TRUST  
STATEMENTS OF CHANGES IN TRUST CORPUS

(\$ in thousands)

(Unaudited)

	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
TRUST CORPUS: Beginning of period	\$456,415	\$462,918
Additional cash reserves	71	131
Amortization of investment in royalty interest	(12,917	) (38,635
Change in derivative liability	(7,595	) 11,560
Distributable income	27,020	91,840
Distributions paid to unitholders	(27,020	) (91,840
TRUST CORPUS: September 30, 2012	\$435,974	\$435,974

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

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CHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS  
(Unaudited)

1. Organization of the Trust

Chesapeake Granite Wash Trust (the “Trust”) is a statutory trust formed on June 29, 2011 by Chesapeake Energy Corporation (“Chesapeake”) 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 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 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 been or that are to be drilled on properties held by Chesapeake within an area of mutual interest (the “AMI”) in Washita County in western Oklahoma. Pursuant to a development agreement with the Trust, Chesapeake intends to drill, or participate as a non-operator in the drilling of, the 118 Development Wells by June 30, 2015 and is obligated to complete such drilling by June 30, 2016.

Additionally, based on Chesapeake’s assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well.

Chesapeake has retained an interest in each of the Producing Wells and Development Wells and currently operates 95% of the Producing Wells and the completed Development Wells and expects to operate approximately 89% of the remaining Development Wells.

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

Through an initial public offering in November 2011, the Trust sold to the public 23,000,000 common units, representing beneficial interests in the Trust, including 3,000,000 common units sold pursuant to the option to purchase additional units exercised by the underwriters, for cash proceeds of approximately \$409.7 million, net of \$27.3 million in underwriting and structuring fees. The Trust delivered the net proceeds of the initial public offering, along with 12,062,500 common units and 11,687,500 subordinated units, to certain wholly owned subsidiaries of Chesapeake in exchange for the conveyance of the Royalty Interests to the Trust. Upon completion of these transactions, there were 46,750,000 Trust units issued and outstanding, consisting of 35,062,500 common units and 11,687,500 subordinated units. The common units and subordinated units have identical rights and privileges, except with respect to their voting rights and rights to receive distributions as described below.

The subordinated units are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is no less than 80% of the target distribution for the corresponding quarter (the “subordination threshold”). If there is not sufficient cash to fund such a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination

threshold amount on the common units. In exchange for agreeing to subordinate a portion of its Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter is 20% greater than the target distribution for such quarter (the “incentive threshold”). The remaining 50% of cash available

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

for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. At the end of the fourth full calendar quarter following Chesapeake's satisfaction of its drilling obligation with respect to the Development Wells, the subordinated units will automatically convert into common units on a one-for-one basis and Chesapeake's right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share on a pro rata basis in the Trust's distributions.

The aggregate distributions paid in the nine months ended September 30, 2012 were \$1.9965 per common unit and \$1.8684 per subordinated unit. The first two distributions, paid on March 1, 2012 and May 31, 2012, were above the subordination threshold and below the incentive threshold for the corresponding distribution period. However, the distributable income available for the distribution paid on August 30, 2012 to unitholders of record as of August 20, 2012, covering production from March 1, 2012 to May 31, 2012, was below the subordination threshold of \$0.6100, resulting in a payment of \$0.6100 per common unit and \$0.4819 per subordinated unit. All of the subordinated units are held by Chesapeake. See "Risk and Uncertainties" in Note 2 below.

Neither the Trust nor the Trustee is responsible for, or has any control over, any costs related to the drilling of the Development Wells or any other operating or capital costs of the Underlying Properties. The Trust's cash receipts with respect to the Royalty Interests in the Underlying Properties are determined after deducting certain post-production expenses and any applicable taxes associated with the Royalty Interests. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, NGL and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by affiliates of Chesapeake. Cash distributions to unitholders will be increased or decreased by the effect of the Trust's hedging arrangements and reduced by the Trust's general and administrative expenses. See "Hedging Arrangements" in Note 3 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.

## 2. Basis of Presentation and Significant Accounting Policies

**Basis of Accounting.** The accompanying Statement of Assets, Liabilities and Trust Corpus as of December 31, 2011, which has been derived from audited financial statements, and the unaudited interim financial statements of the Trust as of September 30, 2012 and for the three and nine month periods ended September 30, 2012, have been presented in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") and include all adjustments which are, in the opinion of the Trustee, necessary for a fair statement of the results for the interim periods presented. The accompanying unaudited interim financial statements should be read in conjunction with the December 31, 2011 audited financial statements and notes of the Trust included in the Trust's Annual Report on Form 10-K for the year ended December 31, 2011.

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



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

Use of Estimates. The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets, liabilities and Trust corpus during the reporting period. Significant estimates that impact the Trust's financial statements include estimates of proved oil and natural gas reserves, which are used

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

to compute the Trust's amortization of Investment in Royalty Interests and, as necessary, to evaluate potential impairments of Investment in Royalty Interests and of the fair value of derivatives. Actual results could differ from those estimates.

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

Additionally, the Trust's exposure to low prices for NGL and natural gas production volumes for the production periods from March 1, 2012 to August 31, 2012 resulted in per unit income available for distribution below the applicable subordination threshold and, accordingly, the Trust paid a common unit distribution at the subordination threshold of \$0.6100 and a subordinated unit distribution of \$0.4819 on August 30, 2012, covering production from March 1, 2012 to May 31, 2012, and will pay a common unit distribution at the subordination threshold of \$0.6300 and a subordinated unit distribution of \$0.2208 on November 29, 2012, covering production from June 1, 2012 to August 31, 2012. Sustained low commodity prices will reduce the Trust's revenues and distributable income available to unitholders, and may result in future distributions to common unitholders at or below the subordination threshold. Chesapeake's ability to perform its obligations to the Trust will depend on its future financial condition and economic performance and access to capital, which in turn will depend upon the supply and demand for oil, NGL and natural gas, its ability to monetize or sell certain assets, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

If Chesapeake were to default on its obligation to drill the Development Wells, the Trust would be able to foreclose on a drilling support lien (the "Drilling Support Lien") to the extent of Chesapeake's remaining interests in the undeveloped portions of the AMI, file a lawsuit to collect money damages from Chesapeake and pursue other available legal remedies against Chesapeake. However, the Trust is not permitted to obtain specific performance from Chesapeake of its drilling obligation and the maximum amount the Trust can recover in a foreclosure or other action is limited to approximately \$146.9 million as of November 9, 2012. The maximum amount that may be recovered under the Drilling Support Lien will decrease as the remaining Development Wells are drilled and completed.

Delays and expenses associated with a foreclosure could reduce distributions to the Trust unitholders by reducing the amount of proceeds available for distribution and may result in the loss of acreage due to leasehold expirations. Any amounts actually recovered in a foreclosure action would be applied to completion of Chesapeake's drilling obligation, would not result in any distribution to the Trust unitholders and may be insufficient to drill the number of wells needed for the Trust to realize the full value of the Royalty Interests in the Development Wells.

In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed the Royalty Interests to the Trust, the Trust could lose the value of all of the Royalty Interests if a bankruptcy court were to hold that the Royalty Interests constitute an asset of the bankruptcy estate. Chesapeake could also be unable to provide support to the Trust through loans and performance of its management duties.

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

**Investment in Royalty Interests.** The 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 is 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. The Trust is not burdened by development costs of the 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.

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

On a quarterly basis, the Trust evaluates the carrying value of the Investment in Royalty Interests under the full cost accounting method prescribed by the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, the carrying value of the Investment in Royalty Interests may not exceed an amount equal to the sum of the present value (using a 10% discount rate) of the estimated future net revenues from proved reserves. Any write-downs resulting from the ceiling test will be non-cash charges to Trust corpus and will not affect distributable income.

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

The Trust records gains or losses from the derivative contracts conveyed under the hedging arrangements when proceeds are received or payments are made, respectively. Additionally, changes in the fair value of the derivative contracts are accounted for as an adjustment to Trust corpus and the fair value carried on the statement of assets, liabilities and trust corpus.

**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 statement of assets, liabilities and trust corpus until repaid. Loans neither increase or decrease distributions to unitholders, however, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid.

**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.

### 3. Hedging Arrangements

The Trust uses derivative instruments to manage its exposure to variability in cash flow from changes in oil and NGL prices.

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

The Trust's obligations to the counterparty under the hedging arrangements are secured by proved reserves attributable to the Trust's interest in the Underlying Properties. The counterparty's obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts owed to the Trust exceeds defined thresholds. Mark-to-market amounts did not exceed the defined thresholds as of September 30, 2012.

As of September 30, 2012, the Trust had the following oil derivative contracts:

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NOTES TO FINANCIAL STATEMENTS – (Continued)  
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Production Quarter	Fixed-Price Oil Swaps		Fair Value (\$ in thousands)
	Volume (mdbl)	Weighted Avg. Price (per bbl)	
Q2 2012 <sup>(1)</sup>	56.4	\$86.17	\$(123 )
Q3 2012 <sup>(2)</sup>	176.6	86.40	(722 )
Q4 2012	185.5	86.98	(1,169 )
Q1 2013	182.2	87.37	(1,146 )
Q2 2013	184.3	87.60	(1,171 )
Q3 2013	187.9	87.79	(1,114 )
Q4 2013	184.2	87.99	(959 )
Q1 2014	179.8	88.08	(780 )
Q2 2014	180.3	88.21	(624 )
Q3 2014	178.8	88.34	(493 )
Q4 2014	174.3	88.45	(372 )
Q1 2015	171.0	88.59	(225 )
Q2 2015	175.4	88.76	(90 )
Q3 2015	153.6	88.90	7 )
Total	2,370.3	\$87.90	\$(8,981 )

(1) Includes June 2012 production that was settled in November 2012.

(2) Includes July and August 2012 production that was settled in November 2012.

To the extent oil production falls below the hedged oil volume, the hedging arrangements will also cover NGL production. Such estimated production of NGL is hedged with oil contracts using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. Since late 2011, NGL prices have decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the hedging arrangements will not effectively mitigate the price risk of the Trust's NGL production.

In accordance with accounting guidance for derivatives and hedging, and because a legal right of set-off exists, the Trust has netted the value of its hedging arrangements with the counterparty in the accompanying statement of assets, liabilities and trust corpus. Derivative liability reflected as short-term represents the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices as of September 30, 2012. The Trust does not apply hedge accounting to any of its derivative instruments, and therefore, any changes in the fair value of the derivative contracts prior to settlement will be accounted for as an adjustment to Trust corpus. Results of settled derivative contracts are reflected in distributable income in the period when paid. For the three months and nine months ended September 30, 2012 the Trust settled derivative contracts that resulted in a payment to the counterparty of \$2.6 million and \$6.0 million, respectively.

#### 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.

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

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.

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

The administrative services agreement will terminate upon the earliest to occur of (a) the date the Trust shall have dissolved and wound up its business and affairs in accordance with the Trust Agreement, (b) the date that all of the Royalty Interests have been terminated or are no longer held by the Trust, (c) with respect to services to be provided with respect to any Underlying Properties being transferred by Chesapeake, the date that either Chesapeake or the Trustee may designate by delivering 90-days prior written notice, provided that Chesapeake's drilling obligation has been completed and the transferee of such Underlying Properties assumes responsibility to perform the services in place of Chesapeake or (d) a date mutually agreed by Chesapeake and the Trustee.

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

In drilling the Development Wells, Chesapeake is required to act diligently and as a reasonably prudent oil and gas operator would act under the same or similar circumstances as if it were acting with respect to its own properties, disregarding the existence of the Royalty Interests as burdens affecting such properties (the "Reasonably Prudent Operator Standard"). Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the Development Wells will be generally consistent with those used for the Producing Wells, the existing Development Wells, and other Colony Granite Wash producing wells outside of the AMI.

Under the development agreement, Chesapeake will be credited for drilling one full Development Well if the perforated length of the well is equal to or greater than 3,500 feet and Chesapeake's net revenue interest in the well is equal to 52.0%. For wells with a perforated length that is less than 3,500 feet, and for wells in which Chesapeake has a net revenue interest greater than or less than 52.0%, Chesapeake receives proportionate credit.

A wholly owned subsidiary of Chesapeake has granted to the Trust the Drilling Support Lien covering Chesapeake's retained interest in the AMI (except its interest in the Producing Wells, Development Wells and any other wells not subject to the Royalty Interests) in order to secure the estimated amount of the drilling costs for the Trust's interests in the Development Wells. The maximum amount that may be obtained by the Trust pursuant to the Drilling Support Lien initially could not exceed \$262.7 million. As Chesapeake fulfills its drilling obligation over time, the total amount that may be recovered will be proportionately reduced and the completed Development Wells will be released from the lien. If Chesapeake does not fulfill its drilling obligation by June 30, 2016, the Trust may foreclose on any remaining interest in the AMI that is subject to the Drilling Support Lien. Any amounts actually recovered in a



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

foreclosure action would be applied to the completion of Chesapeake's drilling obligation and would not result in any distribution to the Trust unitholders.

Chesapeake's drilling activity with respect to the Development Wells is consistent with its intent to meet the drilling obligation contemplated by the development agreement. As of November 9, 2012, Chesapeake had drilled and completed, or caused to be drilled or completed, a total of 47 wells in the AMI (approximately 52.0 Development Wells as calculated under the development agreement), reducing the amount that may be recovered under the Drilling Support Lien to approximately \$146.9 million.

The Trust also entered into a registration rights agreement for the benefit of Chesapeake and certain of its affiliates (each, a "holder"). Pursuant to the registration rights agreement, the Trust agreed to register the Trust units held by each such holder for resale under the Securities Act of 1933, as amended. In connection with the preparation and filing of any registration statement, Chesapeake will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust, and any underwriting discounts and commissions, which will be borne by the seller of the Trust units.

**Loan Commitment.** Pursuant to the Trust Agreement, if at any time the Trust's cash on hand (including available cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will loan funds to the Trust necessary to pay such expenses. Any funds loaned by Chesapeake pursuant to this commitment will be limited to the payment of current accounts payable or other obligations to trade creditors in connection with obtaining goods or services or the payment of other current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans funds pursuant to this commitment, unless Chesapeake agrees otherwise, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid. As of December 31, 2011, a \$0.2 million non-interest bearing loan was outstanding with Chesapeake, which loan was repaid in February 2012.

#### 6. Fair Value Measurement

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

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

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of September 30, 2012:

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NOTES TO FINANCIAL STATEMENTS – (Continued)  
(Unaudited)

	Quoted Prices in Active Markets (Level 1) (\$ in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative liabilities	\$—	\$ (8,981	) \$—	\$ (8,981 )
Total	\$—	\$ (8,981	) \$—	\$ (8,981 )

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2011:

	Quoted Prices in Active Markets (Level 1) (\$ in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative liabilities	\$—	\$ (20,541	) \$—	\$ (20,541 )
Total	\$—	\$ (20,541	) \$—	\$ (20,541 )

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

**7. Distributions to Unitholders**

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's expenses, approximately 60 days following the completion of each quarter through (and including) the quarter ending June 30, 2031. On August 10, 2012, the Trust declared a cash distribution of \$0.6100 per common unit and \$0.4819 per subordinated unit, consisting of proceeds attributable to production from March 1, 2012 through May 31, 2012, to record unitholders as of August 20, 2012. The distribution was paid on August 30, 2012.

**8. Subsequent Events**

On November 7, 2012, the Trust declared a cash distribution of \$0.6300 per common unit and \$0.2208 per subordinated unit, consisting of proceeds attributable to production from June 1, 2012 to August 31, 2012, to record unitholders as of November 19, 2012. The distribution will be paid on November 29, 2012. The Trust's quarterly income available for distribution was \$0.5277 per unit, which was \$0.1023 below the subordination threshold. As a result, the distribution per common unit will be the subordination threshold of \$0.6300 for the quarter. Distributable income attributable to production from June 1, 2012 to August 31, 2012 was calculated as follows (in thousands except for unit and per unit amounts):

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

Revenues:	
Royalty income <sup>(1)</sup>	\$25,756
Total Revenues	\$25,756
Expenses:	
Production taxes	361
Trust administrative expenses <sup>(2)</sup>	350
Derivative settlement loss	375
Total Expenses	1,086
Distributable income available to unitholders	\$24,670
Distributable income per common unit (35,062,500 units issued and outstanding)	\$0.6300
Distributable income per subordinated unit (11,687,500 units issued and outstanding)	\$0.2208

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(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

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ITEM 2. 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 Trust's unaudited interim financial statements and the accompanying notes relating to the Trust and the Underlying Properties included in Item 1 of Part I of this Quarterly Report as well as the Trust's Annual Report on Form 10-K for the year ended December 31, 2011 (the "2011 Form 10-K"). Capitalized items in this Item 2 have the same meanings ascribed to them in Note 1 to the Trust's financial statements included in Item 1 of Part I of this Quarterly Report.

Overview

The Trust is a statutory trust created under the Delaware Statutory Trust Act in June 2011. 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 hedging arrangements (described in Note 3 to the financial statement contained in Part I, Item 1 of this Quarterly Report) and to perform certain administrative functions in respect of the Royalty Interests and the Trust units. The Trust derives all or substantially all of its income and cash flow from the Royalty Interests and the hedging arrangements. The Trust is treated as a partnership for federal income tax purposes. During November 2011, the Trust completed an initial public offering of its common units representing beneficial interests in the Trust, the net proceeds of which were remitted to Chesapeake as partial consideration for its conveyance of the Royalty Interests to the Trust.

Concurrent with the initial public offering, 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 been or that are to be drilled in the Colony Granite Wash play on properties within the AMI. Chesapeake is obligated to drill, or participate as a non operator in the drilling of, the Development Wells from drill sites in the AMI on or prior to June 30, 2016. Additionally, based on Chesapeake's assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. As of September 30, 2012, Chesapeake had drilled and completed 44 wells within the AMI (approximately 47.8 Development Wells as calculated under the development agreement). As of November 9, 2012, Chesapeake had drilled and completed, or caused to be drilled and completed, a total of 47 wells within the AMI (approximately 52.0 Development Wells as calculated under the development agreement).

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

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

On November 16, 2011, Chesapeake novated to the Trust, and the Trust became party to, derivative contracts covering a portion of the production attributable to the Royalty Interests from October 1, 2011 through September 30, 2015. The Trust's distributable income will include net settlements under these derivative contracts. The value of the derivative contracts as of September 30, 2012 was a net liability of \$9.0 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. The distribution made in the third quarter of 2012, consisting of proceeds attributable to production from March 1, 2012 through May 31, 2012, was made on August 30, 2012 to record unitholders as of August 20, 2012.

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

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

**Subordination Threshold.** In order to provide support for cash distributions on the common units, 11,687,500 units (25% of the outstanding Trust units) are subordinated units. The subordinated units, which are owned by Chesapeake, are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is not less than the applicable subordination threshold for the corresponding quarter as set forth in the Trust Agreement and as shown in the table below. If there is not sufficient cash to fund such a distribution on all of the common units (including the common units held by Chesapeake), the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, up to the subordination threshold amount on all the common units (including the common units held by Chesapeake).

**Incentive Threshold.** In exchange for agreeing to subordinate a portion of its Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter exceeds the incentive threshold for the corresponding quarter as set forth in the Trust Agreement and as shown in the table below. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to the Trust unitholders, including Chesapeake, on a pro rata basis.

At the end of the fourth full calendar quarter following Chesapeake's satisfaction of its drilling obligation with respect to the Development Wells, the subordinated units will automatically convert into common units on a one-for-one basis and Chesapeake's right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share on a pro rata basis in the Trust's distributions. There is no assurance of any minimum distribution at any time.

The following table sets forth the subordination threshold and the incentive threshold for each calendar quarter through the second quarter of 2017:

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Period	Subordination Threshold (\$ per unit)	Incentive Threshold
2012:		
Third Quarter <sup>(1)</sup>	0.63	0.94
Fourth Quarter	0.67	1.01
2013:		
First Quarter	0.69	1.04
Second Quarter	0.69	1.04
Third Quarter	0.71	1.07
Fourth Quarter	0.69	1.04
2014:		
First Quarter	0.69	1.04
Second Quarter	0.68	1.02
Third Quarter	0.69	1.03
Fourth Quarter	0.66	0.99
2015:		
First Quarter	0.66	0.99
Second Quarter	0.68	1.02
Third Quarter	0.64	0.96
Fourth Quarter	0.56	0.84
2016:		
First Quarter	0.51	0.76
Second Quarter	0.47	0.70
Third Quarter	0.44	0.66
Fourth Quarter	0.41	0.62
2017:		
First Quarter	0.39	0.59
Second Quarter	0.37	0.56

(1) A distribution of \$0.6300 per common unit and \$0.2208 per subordinated unit was declared on November 7, 2012 and will be paid on November 29, 2012 to unitholders of record as of November 19, 2012.

## Results of Trust Operations

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

Recently, low natural gas prices combined with stronger oil prices have resulted in increased drilling activity in oil- and NGL-rich plays as operators have reduced uneconomic natural gas drilling activities. The resulting increase in production volumes of NGL led to a significant decrease in the price of NGL in both absolute terms and on a relative basis compared to oil. The Trust's exposure to low prices for NGL and natural gas production volumes for the production period from June 1, 2012 to August 31, 2012 resulted in per unit income available for distribution below the subordination threshold and, accordingly, the Trust will pay a common unit distribution at the subordination threshold of \$0.6300 per common unit for the three-month production period ended August 31, 2012, and a

subordinated unit distribution of \$0.2208 per subordinated unit for such period. The distribution will be paid on November 29, 2012.



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Sustained low commodity prices will reduce the Trust's revenues and distributable income available to unitholders, and may result in future distributions to common unitholders at or below the subordination threshold.

Trust Operations for the Three Months Ended September 30, 2012

On August 10, 2012, the Trust declared a cash distribution of \$0.6100 per common unit and \$0.4819 per subordinated unit covering production for the period from March 1, 2012 through May 31, 2012 to record unitholders as of August 20, 2012. The distribution was paid on August 30, 2012 and is reported as distributable income for the quarter ended September 30, 2012 due to the modified cash accounting method adopted by the Trust. Distributable income attributable to production from March 1, 2012 through May 31, 2012 was calculated as follows (in thousands except for unit and per unit amounts):

Revenues:	
Royalty income <sup>(1)</sup>	\$30,955
Interest income	1
Total Revenues	\$30,956
Expenses:	
Production taxes	797
Trust administrative expenses <sup>(2)</sup>	516
Derivative settlement loss	2,623
Total Expenses	3,936
Distributable income available to unitholders	\$27,020
Distributable income per common unit (35,062,500 units issued and outstanding)	\$0.6100
Distributable income per subordinated unit (11,687,500 units issued and outstanding)	\$0.4819

(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

**Royalty Income.** Royalty income to the Trust for the three-month period ended September 30, 2012 and attributable to production from March 1, 2012 through May 31, 2012 totaled \$31.0 million based upon sales of production attributable to the Royalty Interests of 168 thousand barrels ("mbbls") of oil, 328 mbbls of NGL and 3,144 million cubic feet ("mmcf") of natural gas. Total production for the three-month period was 1,020 thousand barrels of oil equivalent ("mboe"). Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production tax, during the three-month period ended September 30, 2012 were \$97.96 per barrel ("bbl"), \$32.83 per bbl and \$1.17 per thousand cubic feet ("mcf"), respectively. Average sales prices are net of certain post-production expenses, including gathering, storage, compression, transportation, processing, treating, dehydrating and non-affiliate marketing expenses.

**Production Taxes.** Production taxes are calculated as a percentage of oil, NGL and natural gas revenues, net of any applicable tax credits. Production taxes for the three-month period ended September 30, 2012 totaled \$0.8 million, or \$0.78 per barrel of oil equivalent ("boe"), and were approximately 3% of royalty income.

**Derivative Settlement Loss.** The Trust will record gains or losses from the derivative contracts conveyed under the hedging arrangements when proceeds are received or payments are made, respectively. Swaps covering March 1, 2012 through May 31, 2012 production were settled, during the three-month period ended September 30, 2012, with proceeds from royalty income for the same period. Total losses during the period were \$2.6 million, or \$0.06 per Trust unit.

**Distributable Income.** Distributable income paid to the Trust unitholders during the three-month period ended September 30, 2012 and attributable to production from March 1, 2012 through May 31, 2012 was \$27.0 million, or \$0.6100 per common unit and \$0.4819 per subordinated unit, which included a \$0.5 million reduction for Trust administrative expenses and a cash reserve for the payment of future Trust administrative expenses. Distributable income was lower than the target distribution of \$0.76 per unit stated in the prospectus dated November 10, 2011

relating to the initial public offering of the Trust's units (the "Prospectus") primarily as a result of lower than assumed prices for natural gas and NGL that were partially offset by higher than assumed prices for oil, including the impact of

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certain post-production expenses. The average price received for oil sales of \$97.96 per bbl for March 1, 2012 through May 31, 2012 production exceeded the price of \$89.41 per bbl assumed in preparing the target distribution level for the same period. The average price received for NGL sales of \$32.83 per bbl was lower than the price of \$43.23 per bbl assumed in preparing the target distribution level for the same period. The average price received for natural gas sales of \$1.17 per mcf for March 1, 2012 through May 31, 2012 production was lower than the price of \$2.93 per mcf assumed in preparing the target distribution level for the same period.

The distribution paid during the three months ended September 30, 2012 was a subordinated distribution. The calculated distribution was below the subordination threshold resulting in a distribution to common unitholders at the subordination threshold and a lower distribution to the subordinated unitholders. All of the subordinated units are held by Chesapeake.

Development Wells. As of September 30, 2012, all of the Producing Wells were producing and approximately 47.8 Development Wells (as calculated under the development agreement) were completed and producing. The amount that could be recovered under the Drilling Support Lien as of September 30, 2012 was approximately \$156.3 million. In addition, 4.2 Development Wells (as calculated under the development agreement) were drilled in the AMI and subsequently completed in October 2012. As of November 9, 2012, Chesapeake had drilled and completed, or caused to be drilled and completed, a total of 47 wells within the AMI (approximately 52.0 Development Wells as calculated under the development agreement) and the amount that could be recovered under the Drilling Support Lien was approximately \$146.9 million.

Trust Operations for the Nine Months Ended September 30, 2012

Cash distributions for the nine-month period ended September 30, 2012 were \$1.9965 per common unit and \$1.8684 per subordinated unit covering production for the period from September 1, 2011 to May 31, 2012. Distributable income attributable to production from September 1, 2011 to May 31, 2012 was calculated as follows (in thousands except for unit and per unit amounts):

Revenues:	
Royalty income <sup>(1)</sup>	\$ 101,579
Interest income	3
Total Revenues	\$ 101,582
Expenses:	
Production taxes	2,347
Trust administrative expenses <sup>(2)</sup>	1,381
Derivative settlement loss	6,014
Total Expenses	9,742
Distributable income available to unitholders	\$91,840
Distributable income per common unit (35,062,500 units issued and outstanding)	\$ 1.9965
Distributable income per subordinated unit (11,687,500 units issued and outstanding)	\$ 1.8684

(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

Royalty Income. Royalty income to the Trust for the nine-month period ended September 30, 2012 and attributable to production from September 1, 2011 to May 31, 2012 totaled \$101.6 million based upon sales of production attributable to the Royalty Interests of 527 mbbbls of oil, 946 mbbbls of NGL and 8,975 mmcf of natural gas. Total production for the nine-month period was 2,969 mboe. Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production tax, during the nine-month period ended September 30, 2012 were \$93.69 per bbl, \$37.34 per bbl and \$1.88 per mcf, respectively. Average sales prices are net of certain post-production expenses, including gathering, storage, compression, transportation, processing, treating, dehydrating and non-affiliate marketing expenses.

Production Taxes. Production taxes are calculated as a percentage of oil, NGL and natural gas revenues, net of any applicable tax credits. Production taxes for the nine-month period ended September 30, 2012 totaled \$2.3 million, or \$0.79 per boe, and were approximately 2.3% of royalty income.

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**Derivative Settlement Loss.** The Trust will record gains or losses from the derivative contracts conveyed under the hedging arrangements when proceeds are received or payments are made, respectively. Swaps covering October 2011 through May 2012 production were settled, during the nine-month period ended September 30, 2012, with proceeds from royalty income for the same period. Total losses during the period were \$6.0 million, or \$0.13 per unit.

**Distributable Income.** Distributable income paid to the Trust unitholders during the nine-month period ended September 30, 2012 and attributable to production from September 1, 2011 to May 31, 2012 was \$91.8 million, or \$1.9965 per common unit and \$1.8684 per subordinated unit, which included a \$1.4 million reduction for Trust administrative expenses and a cash reserve for the payment of future Trust administrative expenses. Distributable income was lower than the aggregate target distributions of \$2.1800 per unit for the nine months ended September 30, 2012 as stated in the Prospectus primarily as a result of lower than assumed prices for natural gas and NGL that were partially offset by higher than assumed prices for oil, including the impact of certain post-production expenses. The average price received for oil sales of \$93.69 per bbl for September 1, 2011 to May 31, 2012 production exceeded the price of \$86.96 per bbl assumed in preparing the target distribution level for the same period. The average price received for NGL sales of \$37.34 per bbl was lower than the price of \$42.14 per bbl assumed in preparing the target distribution level for the same period. The average price received for natural gas sales of \$1.88 per mcf for September 1, 2011 to May 31, 2012 production was lower than the price of \$2.70 per mcf assumed in preparing the target distribution level for the same period.

**Development Wells.** As of September 30, 2012, all of the Producing Wells were producing and approximately 47.8 Development Wells (as calculated under the development agreement) were completed and producing. The amount that could be recovered under the Drilling Support Lien as of September 30, 2012 was approximately \$156.3 million. In addition, 4.2 Development Wells (as calculated under the development agreement) were drilled in the AMI and subsequently completed in October 2012. As of November 9, 2012, Chesapeake had drilled and completed, or caused to be drilled and completed, a total of 47 wells within the AMI (approximately 52.0 Development Wells as calculated under the development agreement) and the amount that could be recovered under the Drilling Support Lien was approximately \$146.9 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, during periods in which oil prices fall below the fixed price received on derivative contracts, the hedging arrangements. The Trust's primary uses of cash are distributions to Trust unitholders, including, if applicable, incentive distributions to Chesapeake, payments of production taxes, payments of Trust administrative expenses, including any reserves established by the Trustee for future liabilities and repayment of loans, payments for derivative contract settlements and payments of expense reimbursements to Chesapeake for out-of-pocket expenses it incurs on behalf of the Trust. Administrative expenses include payments to the Trustee and the Delaware Trustee as well as a quarterly fee of \$50,000 to Chesapeake pursuant to an administrative services agreement. Each quarter, the Trustee determines the amount of funds available for distribution. Available funds are the excess cash, if any, received by the Trust from the sales of oil, NGL and natural gas production attributable to the Royalty Interests during the quarter, over the Trust's expenses for the quarter and any cash reserve for the payment of liabilities of the Trust, subject in all cases to the subordination and incentive provisions described previously.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. The third calendar quarter 2012 distribution of \$0.6100 per common unit and \$0.4819 per subordinated unit, consisting of proceeds attributable to production from March 1, 2012 through May 31, 2012, was made on August 30, 2012 to record unitholders as of August 20, 2012.

On November 7, 2012, the Trust declared a cash distribution of \$0.6300 per common unit and \$0.2208 per subordinated unit, consisting of proceeds attributable to production from June 1, 2012 to August 31, 2012, to record unitholders as of November 19, 2012. The distribution will be paid on November 29, 2012. The Trust's quarterly income available for distribution was \$0.5277 per unit, which was \$0.1023 below the subordination threshold. As a result, the distribution per common unit will be the subordination threshold of \$0.6300 for the quarter. Distributable income attributable to production from June 1, 2012 to August 31, 2012 was calculated as follows (in thousands

except for unit and per unit amounts):

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Revenues:	
Royalty income <sup>(1)</sup>	\$25,756
Total Revenues	\$25,756
Expenses:	
Production taxes	361
Trust administrative expenses <sup>(2)</sup>	350
Derivative settlement loss	375
Total Expenses	1,086
Distributable income available to unitholders	\$24,670
Distributable income per common unit (35,062,500 units issued and outstanding)	\$0.6300
Distributable income per subordinated unit (11,687,500 units issued and outstanding)	\$0.2208

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(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

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.

The Trust is not responsible for any costs related to the drilling of the Development Wells and 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. As Chesapeake fulfills its drilling obligation over time, Development Wells that are completed or that are perforated for completion and then plugged and abandoned are released from the Drilling Support Lien and the total dollar amount that may be recovered by the Trust for Chesapeake's failure to fulfill its drilling obligation is proportionately reduced.

#### Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements. The Trust has not guaranteed the debt of any other party, nor does the Trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations other than the derivative contracts disclosed in the section "Hedging Arrangements" in Note 3 in Part I, Item I of this Quarterly Report.

#### Critical Accounting Policies and Estimates

Refer to Note 2 of Part I, Item 1 for discussion of significant accounting policies and estimates. Critical accounting policies and estimates relating to the Trust are contained in Item 7 of the 2011 Form 10-K.

#### ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

The discussion in this section provides information about derivative contracts pursuant to hedging arrangements between the Trust and its counterparty effective October 1, 2011. The contracts underlying the hedging arrangements cover a portion of the expected production attributable to the Royalty Interests from the Producing Wells and the Development Wells through September 30, 2015. The derivative contracts are settled in cash and do not require the





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actual delivery of oil at settlement. The contracts are settled based upon NYMEX prices. Under the hedging arrangements, the Trust receives payments directly from its counterparty and is required to pay any amounts owed to its counterparty. The Trust does not have the ability to enter into any additional oil, NGL or natural gas derivative contracts, except in limited circumstances involving the restructuring of the existing oil derivatives contracts. As of September 30, 2012, the Trust had the following oil derivative contracts:

Production Quarter	Fixed-Price Oil Swaps		
	Volume (mbbl)	Weighted Avg. Price (per bbl)	Fair Value (\$ in thousands)
Q2 2012 <sup>(1)</sup>	56.4	\$86.17	\$(123 )
Q3 2012 <sup>(2)</sup>	176.6	86.40	(722 )
Q4 2012	185.5	86.98	(1,169 )
Q1 2013	182.2	87.37	(1,146 )
Q2 2013	184.3	87.60	(1,171 )
Q3 2013	187.9	87.79	(1,114 )
Q4 2013	184.2	87.99	(959 )
Q1 2014	179.8	88.08	(780 )
Q2 2014	180.3	88.21	(624 )
Q3 2014	178.8	88.34	(493 )
Q4 2014	174.3	88.45	(372 )
Q1 2015	171.0	88.59	(225 )
Q2 2015	175.4	88.76	(90 )
Q3 2015	153.6	88.90	7 )
Total	2,370.3	\$87.90	\$(8,981 )

(1) Includes June 2012 production that was settled in November 2012.

(2) Includes July and August 2012 production that was settled in November 2012.

To the extent oil production falls below the hedged oil volume, the hedging arrangements will also cover NGL production. Such estimated production of NGL is hedged with oil contracts using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. Since late 2011, NGL prices have decreased relative to oil prices. To the extent NGL prices remain lower than the conversion ratio assumed in the hedging arrangements, the hedging arrangements will not effectively mitigate the price risk of the Trust's NGL production.

The obligations to the counterparty under the hedging arrangements are secured by the Royalty Interests. The value of the derivative contracts as of September 30, 2012 was a net liability of \$9.0 million.

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

**Credit Risk.** A portion of the Trust's liquidity is concentrated in the derivative contracts described above. The use of oil derivative contracts exposes the Trust to credit risk from its counterparty, which has an investment grade credit rating. **Credit Risk Associated With Chesapeake.** Chesapeake's ability to perform its obligations to the Trust will depend on its future financial condition, economic performance, access to capital and ability to sell assets, which in turn will

depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

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If Chesapeake were to default on its obligation to drill the Development Wells, the Trust would be able to foreclose on the Drilling Support Lien to the extent of Chesapeake's remaining interests in the undeveloped portions of the AMI, file a lawsuit to collect money damages from Chesapeake and pursue other available legal remedies against Chesapeake. However, the Trust is not permitted to obtain specific performance from Chesapeake of its drilling obligation and the maximum amount the Trust can recover in a foreclosure or other action was limited to approximately \$146.9 million as of November 9, 2012 and will decrease as the remaining Development Wells are drilled and completed.

Delays and expenses associated with a foreclosure could reduce distributions to the Trust unitholders by reducing the amount of proceeds available for distribution and may result in the loss of acreage due to leasehold expirations. Any amounts actually recovered in a foreclosure action would be applied to completion of Chesapeake's drilling obligation, would not result in any distribution to the Trust unitholders and may be insufficient to drill the number of wells needed for the Trust to realize the full value of the Royalty Interests in the Development Wells.

In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed the Royalty Interests to the Trust, the Trust could lose the value of all of the Royalty Interests if a bankruptcy court were to hold that the Royalty Interests constitute an asset of the bankruptcy estate. Chesapeake could also be unable to provide support to the Trust through loans and performance of its management duties.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by Chesapeake to The Bank of New York Mellon Trust Company, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosures. As of the end of the period covered by this Quarterly Report, the Trustee carried out an evaluation of the Trustee's disclosure controls and procedures. Mike Ulrich, as Trust Officer of the Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the nature of the Trust as a passive entity and in light of the contractual arrangements pursuant to which the Trust was created, including the provisions of (i) the Trust Agreement, (ii) the administrative services agreement and (iii) the conveyances granting the Royalty Interests, the Trustee's disclosure controls and procedures related to the Trust necessarily rely on (a) information provided by Chesapeake, including information relating to results of operations, the status of drilling of the Development Wells, the costs and revenues attributable to the Trust's interests under the conveyance and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the underlying properties and the Royalty Interests, and (b) conclusions and reports regarding reserves by the Trust's independent reserve engineers.

Changes in Internal Control over Financial Reporting. During the quarter ended September 30, 2012, there has been no change in the Trustee's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trustee's internal control over financial reporting related to the Trust. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of Chesapeake.

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PART II. OTHER INFORMATION

ITEM 1A. Risk Factors

Risk factors relating to the Trust are contained in Item 1A of the 2011 Form 10-K. There have not been any material changes from the risk factors previously disclosed in the 2011 Form 10-K.

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## ITEM 6. Exhibits

The following exhibits are filed or furnished as a part of this report.

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed Herewith	Furnished Herewith
		Form	SEC File Number	Exhibit	Filing Date		
3.1	Certificate of Trust of Chesapeake Granite Wash Trust.	S-1	333-175395	3.1	7/7/2011		
3.2	Amended and Restated Trust Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake Exploration, L.L.C., The Bank of New York Mellon Trust Company, N.A., as Trustee, Trustee and The Corporation Trust Company, as Delaware Trustee.	8-K	001-35343	3.1	11/21/2011		
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

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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: November 14, 2012

CHESAPEAKE GRANITE WASH TRUST

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

By: /s/ Michael J. Ulrich  
Michael J. Ulrich  
Vice President

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

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