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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

for The Fiscal Year Ended December 31, 2013

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**

for the transition period from to

Commission File Number 001-34800

ECA Marcellus Trust I

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**27-6522024** (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** (Address of principal executive offices)	**78701** (Zip Code)

Registrant's telephone number, including area code: **(512) 236-6555**

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Units of Beneficial Interest	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒ .

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 ☒ .

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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. ☒

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

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

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

The aggregate market value of Units of Beneficial Interest in ECA Marcellus Trust I held by non-affiliates on June 30, 2013, the last business day of the registrant's most recently completed second fiscal quarter was $139,080,581.

As of March 14, 2014, 17,605,000 Common Units of Beneficial Interest in ECA Marcellus Trust I were outstanding.

Documents Incorporated By Reference: None

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References to the "Trust" in this document refer to ECA Marcellus Trust I. References to "ECA" in this document refer to Energy Corporation of America and its wholly-owned subsidiaries, and when discussing the conveyance documents, the Private Investors.

FORWARD-LOOKING STATEMENTS

This Form 10-K contains "forward-looking statements" about ECA and the Trust and other matters discussed herein that are subject to risks and uncertainties. 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" and "Risk Factors" regarding the financial position, business strategy, production and reserve growth, development activities and costs and other plans and objectives for the future operations of ECA and all matters relating to the Trust are forward-looking statements. Actual outcomes and results may differ materially from those projected.

When used in this document, the words "believes," "expects," "anticipates," "intends" or similar expressions, are intended to identify such forward-looking statements. Further, all statements regarding future circumstances or events are forward-looking statements. The following important factors, in addition to those discussed elsewhere in this document, could affect the future results of the energy industry in general, and ECA and the Trust in particular, and could cause those results to differ materially from those expressed in such forward-looking statements:

- risks incident to the operation of natural gas wells;
- future production costs;
- the effect of existing and future laws and regulatory actions;
- the effect of changes in commodity prices;
- the ability of the Trust's hedge counterparties to meet their contractual obligations;
- conditions in the capital markets;
- competition from others in the energy industry;
- the uncertainty of estimates of natural gas reserves and production; and
- other risks described under the caption "Risk Factors" in this Report on Form 10-K.

This Form 10-K describes other important factors that could cause actual results to differ materially from expectations of ECA and the Trust, including under the caption "Risk Factors." All subsequent written and oral forward-looking statements attributable to ECA or the Trust or persons acting on behalf of ECA or the Trust are expressly qualified in their entirety by such factors. The Trust assumes no obligation, and disclaims any duty, to update these forward-looking statements.

GLOSSARY OF CERTAIN TERMS

The following are definitions of certain significant terms used in this report. Other terms are defined in the text of this report.

AMI —The area of mutual interest, or AMI, consisted of the Marcellus Shale formation in approximately 121 square miles of property located in Greene County, Pennsylvania in which ECA had leased approximately 9,300 acres and owned substantially all of the working interests at the date of formation of the Trust. ECA was obligated to drill the 52 development wells from drill sites on approximately 9,300 leased acres in the AMI. Until ECA satisfied its drilling obligation on November 30, 2011, it was not permitted to drill and complete any well in the Marcellus Shale formation within the AMI for its own account.

Basis —the difference between the spot or cash price and the futures price of the same or related commodity. For natural gas, basis equals the local cash market price minus the price of the nearby NYMEX natural gas futures contract.

Bcf —One billion cubic feet of natural gas.

Btu —A British Thermal Unit, a common unit of energy measurement.

Completion —(or its derivatives) means that the well has been perforated, stimulated, tested and permanent equipment for the production of natural gas has been installed.

ECA's retained interest —ECA's retained interest in 10% of the proceeds from the sale of production from the 14 producing Marcellus Shale natural gas wells located in Greene County, Pennsylvania as well as ECA's retained interest in 50% of the proceeds from the sale of production from the PUD Wells drilled in the AMI.

Equivalent PUD Well —is defined as a well that is drilled horizontally in the Marcellus formation for a lateral distance of 2,500 feet measured from the midpoint of the curve to the end of the lateral multiplied by the working interest held by ECA. Wells with a horizontal lateral less than 2,500 feet count as a fractional well in proportion to total lateral length divided by 2,500 feet. Wells with a horizontal lateral greater than 2,500 feet (subject to a maximum of 3,500 feet) will count as Fractional Wells in proportion to the total lateral length divided by 2,500 feet.

Farmout agreement —A farmout agreement is typically an agreement under which a lessee under an oil and gas lease agrees to grant to another party the right to drill wells on the tract covered by such lease and to earn certain acreage for drilling such wells.

FASB ASC —means the Financial Accounting Standards Board Accounting Standards Codification.

Fractional well —The fraction (either greater than one or less than one) of a well obtained by dividing the horizontal lateral (measured from the midpoint of the curve) of such well by 2,500 feet (subject to a maximum of 3,500 feet).

Gas —means natural gas and all other gaseous hydrocarbons, excluding condensate, butane, and other liquid and liquefiable components that are actually removed from the Gas stream by separation, processing, or other means.

Incentive Threshold —means, for any particular quarter through the end of the Subordination Period, the amount shown in the column titled "Incentive Threshold" in the section titled "Overview" in Management's Discussion and Analysis in this report. In exchange for agreeing to subordinate the 4,401,250 Trust units it originally acquired, and in order to provide additional financial incentive to ECA to perform its drilling obligation and operations on the Underlying Properties in an efficient and cost-effective manner, ECA 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 exceeded 150% of the subordination threshold for such quarter. ECA's right to receive the incentive distributions terminated upon the expiration of the Subordination Period.

MMBtu —One million British Thermal Units.

Mcf —One thousand cubic feet of natural gas.

MMcf —One million cubic feet of natural gas.

Net Profits Interest —A nonoperating interest that creates a share in gross production from an operating or working interest in oil and natural gas properties. The share is measured by net profits from the sale of production after deducting costs associated with that production.

Perpetual PDP Royalty Interests —means the interests entitling holders to receive 45% of the proceeds from the sale of production of natural gas attributable to the interests of ECA in the Producing Wells (after deducting post-production costs and any applicable taxes).

Perpetual PUD Royalty Interests —means the interests entitling holders to receive 25% of the proceeds from the sale of production of natural gas attributable to ECA's interest in the PUD Wells (after deducting post-production costs and any applicable taxes).

Perpetual Royalty Interests —a term that collectively references the Perpetual PDP Royalty Interests and the Perpetual PUD Royalty Interests.

Private Investors —the persons described as the "Private Investors" in the Prospectus.

Prospectus —the prospectus dated July 1, 2010 and filed with the SEC pursuant to Rule 424(b) on July 1, 2010 relating to the initial public offering of the Trust Units.

Proved developed reserves —Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves —Under SEC rules for fiscal years ending on or after December 31, 2009, proved reserves are defined as:

Those quantities of oil and 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. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or 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, LKH, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil, HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be 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.

SEC —means the United States Securities and Exchange Commission.

Subject Gas —means Gas from the Marcellus Shale formation from any Producing Well or PUD Well.

Subject Interest —means ECA's undivided interests in the AMI, as lessee under Gas leases, as an owner of the Subject Gas (or the right to extract such Gas), or otherwise, by virtue of which undivided interests ECA has the right to conduct exploration and gas production operations on the AMI.

Subordination Period —means the period during which 4,401,250 of the Trust units originally acquired by ECA were subject to the subordination provisions described herein. Because ECA met its drilling obligation to the Trust on November 30, 2011, the Subordination Period expired on December 31, 2012; and the last cash distribution supported by the subordinated units was the cash distribution payable with respect to the proceeds for the fourth quarter of 2012.

Subordination Threshold —means, for any particular quarter (through the Subordination Period), the amount shown in the column titled "Subordination Threshold" in the section titled "Overview" in Management's Discussion and Analysis in this report. In order to provide support for cash distributions on the common units, ECA had agreed to subordinate 4,401,250 of the Trust units it acquired, which constituted 25% of the outstanding Trust units. While the subordinated units were entitled to receive pro rata distributions from the Trust if and to the extent there was sufficient cash to provide a cash distribution on the common units that was at least equal to the applicable quarterly subordination threshold, if there was not sufficient cash to fund such a distribution on all Trust units, the distribution made with respect to the subordinated units was reduced or eliminated in order to make a distribution, to the extent possible, of up to the Subordination Threshold amount on the common units.

Term PDP Royalty Interests —means the interests entitling holders to receive 45% of the proceeds from the sale of production of natural gas attributable to ECA's interest in the Producing Wells (after deducting post-production costs and any applicable taxes) for a period of 20 years commencing on April 1, 2010.

Term PUD Royalty Interests —means the interests entitling holders to receive 25% of the proceeds from the sale of production of natural gas attributable to ECA's interest in the PUD Wells (after deducting post-production costs and any applicable taxes) for a period of 20 years commencing on April 1, 2010.

Term Royalty Interests —a term that collectively references the Term PDP Royalty Interests and the Term PUD Royalty Interests.

Trust Gas —means that percentage of Gas to which the Trust is entitled, calculated in accordance with the provisions of the conveyances of the royalty interests.

Working interest —The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

PART I

Item 1. *Business*

Introduction

ECA Marcellus Trust I is a statutory trust formed in March 2010 under the Delaware Statutory Trust Act, pursuant to a Trust Agreement (the "Trust Agreement") among Energy Corporation of America ("ECA"), as Trustor, The Bank of New York Mellon Trust Company, N.A., as Trustee (the "Trustee"), and Wilmington Trust Company, as Delaware Trustee (the "Delaware Trustee"). The Trust maintains its offices at the office of the Trustee, at 919 Congress Avenue, Suite 500, Austin, Texas 78701. The telephone number of the Trustee is 1-800-852-1422.

The Trust makes copies of its reports under the Exchange Act available at www.businesswire.com/cnn/ect.htm. The Trust's filings under the Exchange Act are also available electronically from the website maintained by the Securities and Exchange Commission ("SEC") at http://www.sec.gov. The Trust will also provide electronic and paper copies of its filings free of charge upon request to the Trustee.

General

The Trust does not conduct any operations or activities. The Trust's purpose is, in general, to hold the Royalty Interests (described below), to distribute to the Trust unitholders cash that the Trust receives in respect of the Royalty Interests after the payment of Trust expenses, and to perform certain administrative functions in respect of the Royalty Interests and the Trust units. The Trustee has no authority or responsibility for, and no involvement with, any aspect of the oil and gas operations on the properties to which the Royalty Interests relate. The Trust derives all or substantially all of its income and cash flows from the Royalty Interests, which in turn are subject to the hedge contracts described in this report. The Trust is treated as a partnership for federal and state income tax purposes.

Initially, the Trust owned royalty interests in the 14 Producing Wells described in the Prospectus (the "Producing Wells") and royalty interests in 52 horizontal natural gas development wells to be drilled to the Marcellus Shale formation (the "PUD Wells") within the AMI, in which ECA held approximately 9,300 acres, of which it owned substantially all of the working interests, in Greene County, Pennsylvania. The AMI consisted of the Marcellus Shale formation in approximately 121 square miles in Greene County, Pennsylvania.

ECA completed its drilling obligation to the Trust under the Development Agreement as of November 30, 2011. This completion date was approximately 2.3 years in advance of the required completion date of March 31, 2014. Consequently, no additional wells will be drilled for the Trust, and the subordinated units automatically converted on a one-for-one basis into ECT common units on December 31, 2012. The last cash distribution supported by the ECT subordinated units was the cash distribution payable with respect to the proceeds for the fourth quarter of 2012. Beginning with the cash distribution payable with respect to the first quarter of 2013, all ECT Trust units share in all cash distributions on a pro rata basis. As of December 31, 2013 the Trust owns Royalty Interests in the 14 Producing Wells and the 40 development wells (52.06 Equivalent PUD Wells calculated in accordance with the Development Agreement and as described in the Prospectus) that are now completed and in production. The 14 Producing Wells and the 40 development wells (52.06 Equivalent PUD Wells) are sometimes herein called the "Trust Wells".

The royalty interests were conveyed from ECA's working interest in the Producing Wells and the PUD Wells limited to the Marcellus Shale formation (the "Underlying Properties"). The royalty interest in the Producing Wells (the "PDP Royalty Interest") entitles the Trust to receive 90% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of production of natural gas attributable to ECA's interest in the Producing Wells for a period of 20 years commencing on April 1, 2010 and 45% thereafter. The royalty interest in the PUD Wells (the "PUD Royalty Interest" and together with the PDP Royalty Interest, the "Royalty Interests") entitles the Trust to receive 50% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of production of natural gas attributable to ECA's interest in the PUD Wells for a period of 20 years commencing on April 1, 2010 and 25% thereafter. As used herein, the term "Producing Wells" means the 14 Producing Wells as defined above, and does not include the 40 PUD Wells, although they also have been completed and are producing. Approximately 50% of the originally estimated natural gas production attributable to the Trust's Royalty Interests has been hedged through March 31, 2014. A more complete description of the hedge contracts is provided in this report.

ECA was obligated to drill all of the PUD Wells no later than March 31, 2014. As of November 30, 2011, ECA had fulfilled its drilling obligation to the Trust by drilling 40 PUD Wells (52.06 Equivalent PUD Wells), calculated as provided in the Development Agreement. The Trust was not responsible for any costs related to the drilling of development wells or any other development or operating costs. The Trust's cash receipts in respect of the Royalty Interests is determined after deducting post-production costs and any applicable taxes associated with the Royalty Interests, and the Trust's cash available for distribution includes any cash receipts from the hedge contracts and is reduced by Trust administrative expenses. Post-production costs generally consist of costs incurred to gather, compress, transport, process, treat, dehydrate and market the natural gas produced. Charges (the "Post-Production Services Fee") payable to ECA for such post-production costs on its Greene County Gathering System were limited to $0.52 per MMBtu gathered until ECA fulfilled its drilling obligation; thereafter, ECA may increase the Post-Production Services Fee to the extent necessary to recover certain capital expenditures in the Greene County Gathering System.

Generally, the percentage of production proceeds to be received by the Trust with respect to a well equals the product of (i) the percentage of proceeds to which the Trust is entitled under the terms of the conveyances (90% for the Producing Wells and 50% for the PUD Wells) multiplied by (ii) ECA's net revenue interest in the well. ECA on average owns an 81.53% net revenue interest in the Producing Wells. Therefore, the Trust is entitled to receive on average 73.37% of the proceeds of production from the Producing Wells. With respect to the PUD Wells, the conveyance related to the PUD Royalty Interest provides that the proceeds from the PUD Wells are calculated on the basis that the underlying PUD Wells are burdened only by interests that in total would not exceed 12.5% of the revenues from such properties, regardless of whether the royalty interest owners are actually entitled to a greater percentage of revenues from such properties. As an example, assuming ECA owns a 100% working interest in a PUD Well, the applicable net revenue interest is calculated by multiplying ECA's percentage working interest in the 100% working interest well by the unburdened interest percentage (87.5%) and such well would have a minimum 87.5% net revenue interest. Accordingly, the Trust is entitled to a minimum of 43.75% of the production proceeds from the well provided in this example. To the extent ECA's working interest in a PUD Well is less than 100%, the Trust's share of proceeds would be proportionately reduced.

Historical Target Distributions and Subordination and Incentive Thresholds

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting Trust administrative expenses, including the costs incurred as a result of being a publicly traded entity, on or about 60 days following the completion of each quarter. The Trust will liquidate on or about March 31, 2030.

The amount of Trust revenues and cash distributions to Trust unitholders will depend on, among other things:

- natural gas prices received;
- the volume and Btu rating of natural gas produced and sold;

- post-production costs and any applicable taxes;
- administrative expenses of the Trust including expenses incurred as a result of being a publicly traded entity, and any changes in amounts reserved for such expenses; and
- through March 31, 2014, the effects of the hedging arrangements.

The amount of the quarterly distributions will fluctuate from quarter to quarter, depending on the proceeds received by the Trust, among other factors. There is no minimum required distribution. In order to provide support for cash distributions on the common units for a limited period of time, ECA agreed to subordinate 4,401,250 of the Trust units it originally acquired, which constituted 25% of the outstanding Trust units. 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 which was at least equal to the applicable quarterly subordination threshold. However, if there was not sufficient cash to fund such a distribution on all Trust units, the distribution with respect to the subordinated units was 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 these Trust units, and in order to provide additional financial incentive to ECA to perform its drilling obligation and operations on the Underlying Properties in an efficient and cost-effective manner, ECA 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 exceeded 150% of the subordination threshold for such quarter. ECA's right to receive the incentive distributions, and the benefit of the subordination provisions to the holders of the common units, terminated upon the expiration of the Subordination Period.

The subordinated units automatically converted into common units on a one-for-one basis and ECA's right to receive incentive distributions terminated on December 31, 2012. Because the Subordination Period terminated on December 31, 2012, the fourth quarter of 2012 was the last quarter that the common unitholders were eligible to receive a distribution in the amount of the Subordination Threshold. The table below sets forth the Target Distributions and the Subordination and Incentive Thresholds for each calendar quarter through the fourth quarter of 2012.

The effective date of the Trust was April 1, 2010, meaning the Trust has received the proceeds of production attributable to the PDP Royalty Interest from that date even though the PDP Royalty Interest was not conveyed to the Trust until July 7, 2010.

Period	Subordination Threshold	Target Distribution	Incentive Threshold
		(per unit)	
2010:			
Second Quarter	$ 0.181	$ 0.227	$ 0.272
Third Quarter	0.334	0.417	0.501
Fourth Quarter	0.478	0.597	0.716
2011:			
First Quarter	0.446	0.558	0.669
Second Quarter	0.451	0.564	0.676
Third Quarter	0.550	0.688	0.825
Fourth Quarter	0.565	0.706	0.847
2012:			
First Quarter	0.574	0.717	0.861
Second Quarter	0.602	0.752	0.903
Third Quarter	0.624	0.780	0.937
Fourth Quarter	0.701	0.876	1.051

Because the Subordination Period has ended, the foregoing table is provided solely for historical information. Effective with the distribution related to the first quarter of 2013, there has been no Subordination Threshold, Target Distribution or Incentive Threshold, and all units, including the formerly subordinated units, have shared distributions pro rata.

Pursuant to IRC Section 1446, withholding tax on income effectively connected to a United States trade or business allocated to foreign partners should be made at the highest marginal rate. Under Section 1441, withholding tax on fixed, determinable, annual, periodic income from United States sources allocated to foreign partners should be made at 30% of gross income unless the rate is reduced by treaty. This release is intended to be a qualified notice to nominees and brokers as provided for under Treasury Regulation Section 1.1446-4(b) by ECA Marcellus Trust I, and while specific relief is not specified for Section 1441 income, this disclosure is intended to suffice. Nominees and brokers should withhold 39.6% of the distribution made to foreign partners.

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting Trust administrative expenses, including the costs incurred as a result of being a publicly traded entity, on or about 60 days following the completion of each quarter. The Trust will liquidate on or about March 31, 2030 (the "Termination Date"). At the Termination Date, 50% of each of the PDP Royalty Interest and the PUD Royalty Interest will revert automatically to ECA. The remaining 50% of each of the PDP Royalty Interest and the PUD Royalty Interest will be sold, and the net proceeds will be distributed pro rata to the unitholders soon after the Termination Date. ECA will have a right of first refusal to purchase the remaining 50% of the Royalty Interests at the Termination Date. Because payments to the Trust will be generated by depleting assets and the Trust has a finite life with the production from the Underlying Properties diminishing over time, a portion of each distribution will represent a return of the original investment in the Trust units.

The Trustee can authorize the Trust to borrow money to pay Trust administrative or incidental expenses that exceed cash held by the Trust. The Trustee may authorize the Trust to borrow from the Trustee as a lender provided the terms of the loan are fair to the Trust unitholders, although the Trustee does not intend to make any such loans. The Trustee may also deposit funds awaiting distribution in an account with itself, if the interest paid to the Trust at least equals amounts paid by the Trustee on similar deposits, and make other short term investments with the funds distributed to the Trust. The Trustee may also hold funds awaiting distribution in a non interest bearing account.

The Trust is responsible for paying all legal, accounting, tax advisory, engineering, printing costs and other administrative and out-of-pocket expenses incurred by or at the direction of the Trustee. The Trust is also responsible for paying other expenses, including the expenses of tax return and Schedule K-1 preparation and distribution, and expenses incurred as a result of being a publicly traded entity, including costs associated with annual and quarterly reports to unitholders, independent auditor fees and registrar and transfer agent fees.

The Administrative Services Agreement

The Trust entered into an Administrative Services Agreement with ECA that obligates the Trust to pay ECA each quarter an administrative services fee for accounting, bookkeeping and informational services to be performed by ECA on behalf of the Trust relating to the Royalty Interests. The annual fee of $60,000 is payable in equal quarterly installments. Under certain circumstances, ECA and the Trustee each may terminate the Administrative Services Agreement at any time following delivery of notice no less than 90 days prior to the date of termination.

The Development Agreement

In connection with the formation of the Trust, the Trust entered into a Development Agreement with ECA which obligated ECA to drill all of the PUD Wells no later than March 31, 2014. ECA granted to the Trust a lien on ECA's interest in the Marcellus Shale formation in the AMI (except the Producing Wells and any other wells which were already producing and not subject to the Royalty Interests) in order to secure the estimated amount of the drilling costs for the Trust's interests in the PUD Wells (the "Drilling Support Lien"). The original maximum amount of the Drilling Support Lien was $91 million. As ECA fulfilled its drilling obligation over time, the total dollar amount recovered was proportionately reduced and the completed PUD Wells were released from the lien. As of November 30, 2011, the Drilling Support Lien had been fully released.

For purposes of ECA's drilling obligation, and subject to the following paragraph, ECA was credited with a full development well drilled if its working interest in the development well drilled was 100%. Where ECA's working interest in a development well drilled was less than 100%, ECA was credited with a portion of a development well in the proportion that its working interest in the development well bears to 100%. For example, if ECA's working interest in a development well drilled by ECA in connection with fulfilling its drilling obligation to the Trust was 50%, ECA was credited with one-half of a development well for purposes of satisfying its drilling obligation in the period the development well was drilled.

Wells drilled horizontally with a horizontal lateral distance (measured from the midpoint of the curve to the end of the lateral) of less than 2,500 feet counted as a Fractional well in proportion to total lateral length divided by 2,500 feet. Wells with a horizontal lateral distance of greater than 2,500 feet (subject to a maximum of 3,500 feet) counted as one well plus a Fractional well equal to the length drilled in excess of 2,500 (up to 3,500 feet) feet divided by 2,500 feet.

In accordance with these provisions of the Development Agreement, ECA drilled 40 development wells (52.06 Equivalent PUD Wells) to fulfill its obligation to drill the 52 PUD Wells as required.

ECA was obligated to bear all of the costs of drilling and completing the PUD Wells. ECA was required to complete and equip each development well that reasonably appeared to ECA to be capable of producing gas in quantities sufficient to pay completion, equipping and operating costs. ECA has drilled, completed and equipped each of the development wells.

ECA has agreed not to drill and complete, and not to permit any other person within its control to drill and complete, any well on the lease acreage that would have a perforated segment within 500 feet of any perforated interval of a PUD Well or Producing Well in the Marcellus Shale formation.

Hedging Contracts Transferred to the Trust

In connection with the formation of the Trust, ECA transferred to the Trust natural gas derivative floor price contracts and entered into a back-to-back swap agreement with the Trust to provide the Trust with the benefit of certain contracts entered into between ECA and third parties that, at the formation of the Trust, equated to approximately 50% of the estimated natural gas to be produced by the Trust properties from April 1, 2010 through March 31, 2014. The swap contracts related to approximately 7,500 MMBtu per day at a weighted average price of $6.78 per MMBtu for the period commencing as of April 1, 2010 through June 30, 2012. The price of the floor price hedging contracts is $5.00 per MMBtu for the period commencing October 1, 2010 through March 31, 2014. After March 31, 2014, no hedging arrangements will be in effect.

The following table sets forth the volumes of natural gas covered by the natural gas hedging contracts and the floor price for each quarter during the term of the contracts.

	Swap Volume (MMBtu)	Swap Price (MMBtu)	Floor Volume (MMBtu)	Floor Price (MMBtu)
Second Quarter 2010	682,500	$ 6.75	—	—
Third Quarter 2010	690,000	$ 6.75	—	—
Fourth Quarter 2010	690,000	$ 6.75	225,000	$ 5.00
First Quarter 2011	675,000	$ 6.75	159,000	$ 5.00
Second Quarter 2011	682,500	$ 6.75	210,000	$ 5.00
Third Quarter 2011	690,000	$ 6.82	405,000	$ 5.00
Fourth Quarter 2011	690,000	$ 6.82	384,000	$ 5.00
First Quarter 2012	682,500	$ 6.82	369,000	$ 5.00
Second Quarter 2012	682,500	$ 6.82	516,000	$ 5.00
Third Quarter 2012			1,305,000	$ 5.00
Fourth Quarter 2012			1,362,000	$ 5.00
First Quarter 2013			1,395,000	$ 5.00
Second Quarter 2013			1,380,000	$ 5.00
Third Quarter 2013			1,278,000	$ 5.00
Fourth Quarter 2013			1,188,000	$ 5.00
First Quarter 2014			1,092,000	$ 5.00

Marketing and Post-Production Services

Pursuant to the terms of the conveyances creating the Royalty Interests, ECA has the responsibility to market, or cause to be marketed, the natural gas production related to the Underlying Properties. The terms of the conveyances creating the Royalty Interests do not permit ECA to charge any marketing fee when determining the proceeds upon which the royalty payments are calculated. As a result, the proceeds to the Trust from the sales of natural gas production from the Underlying Properties are determined based on the same price (net of post-production costs) that ECA receives for natural gas production attributable to ECA's retained interest.

ECA markets the majority of its operated production and markets all of the gas produced from the Underlying Properties. ECA enters into gas sales arrangements with large aggregators of supply and these arrangements may be on a month-to-month basis or may be for a term of up to one year or longer. The natural gas is sold at a market price and any applicable post-production costs are deducted.

All of the production from the Producing Wells and the PUD Wells is currently gathered by ECA's Greene County Gathering System. The Trust pays the initial Post-Production Services Fee of $0.52 per MMBtu for use of this system, including ECA's costs to gather, compress, transport, process, treat, dehydrate and market the gas. This fee was fixed until ECA's drilling obligation was satisfied; however, ECA may increase this fee to the extent necessary to recover certain capital expenditures on the Greene County Gathering System made after the completion of the drilling period, provided the resulting charge does not exceed the prevailing charges in the area for similar services. This fee does not include the cost of fuel used in the compression process or equivalent electricity charges when electric compressors are used, firm transportation charges on interstate gas pipelines, or other third-party charges. The Trust's cash available for distribution is reduced by ECA's deductions for these post-production services.

ECA may enter into arrangements with third parties to provide gathering, transportation, processing and other reasonable post-production services, including transportation on downstream interstate pipelines. Such additional post-production costs will be expressed as either (1) a cost per MMBtu or Mcf or (2) a percentage of the gross production from a well. To the extent that post-production costs are expressed as a cost per MMBtu or Mcf, such costs may be deducted by the purchaser of the natural gas prior to payment being made to ECA for such production. At other times, ECA will make payments directly to the third parties providing such post-production services. In either instance, the Trust's cash available for distribution will be reduced by the costs paid by ECA for such post-production services provided by third parties. If the post-production costs 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 Interests are reduced accordingly.

The post-production costs for the Trust's natural gas produced and sold averaged $0.69 and $0.73 per MMBtu for the years ended December 31, 2013 and 2012, respectively. Such costs may increase or decrease in the future. The post-production costs attributable to third party arrangements may be costs established by arms-length negotiations or pursuant to a state or federal regulatory proceeding. ECA is permitted to deduct from the proceeds payable to the Trust other post-production costs necessary to make the natural gas from the Underlying Properties marketable, so long as such costs do not materially exceed the charges prevailing in the area for similar services.

ECA has an agreement with Columbia Gas Transmission, LLC to provide firm transportation downstream of ECA's Greene County Gathering System for 50,000 MMBtu per day. This firm transportation arrangement, which terminates July 31, 2021, has been in effect since August 1, 2011 and is at Columbia Gas Transmission, LLC's filed tariff rate, which initially equated to $0.1996 per MMBtu at one hundred percent load factor. As a result of a filing by Columbia Gas Transmission, LLC with the Federal Energy Regulatory Commission (FERC Docket No. RP12-1021-000), the filed tariff rate was reduced to $0.1878 per MMBtu at one hundred percent load factor retroactively to January 1, 2012, and the Trust received $0.3 million as its proportionate share of the related refund during the second quarter of 2013. This firm transportation is an additional post-production cost and the Trust bears its proportionate share of such costs.

ECA may enter into similar gas supply arrangements and post-production service arrangements for the gas to be produced from the Underlying Properties. Any new gas supply arrangements or those entered into for providing post-production services, will be utilized in determining the proceeds for the Underlying Properties.

Competition and Markets

The natural gas industry is highly competitive. ECA competes with major oil and gas companies and independent oil and gas companies for oil and gas leases, equipment, personnel and markets for the sale of natural gas. Many of these competitors are financially stronger than ECA, but even financially troubled competitors can affect the market because they may need to sell natural gas regardless of price to attempt to maintain cash flow. The Trust is subject to the same competitive conditions as ECA and other companies in the natural gas industry.

Natural gas competes with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for natural gas.

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

Environmental Matters and Regulation

The operations of the properties comprising the Underlying Properties are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with production activities;
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and
- enjoin some or all of the operations of the Underlying Properties deemed in non-compliance with permits issued pursuant to such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations or imposing additional compliance requirements on such operations. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. Moreover, these laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on the operating costs of the properties comprising the Underlying Properties.

The following is a summary of the existing laws, rules and regulations to which the operations of the properties comprising the Underlying Properties are subject that are material to the operation of the Underlying Properties.

Natural gas regulation. The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. The Federal Energy Regulatory Commission's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. Neither ECA nor the Trust can predict whether new legislation to regulate natural gas prices might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the Underlying Properties. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

Environmental regulation. The exploration, development and production operations of ECA are subject to stringent and comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct construction, drilling, water withdrawal and waste disposal operations; govern the amounts and types of substances that may be disposed or released into the environment; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions arising from ECA's operations or attributable to former operations; and impose obligations to reclaim and abandon well sites, impoundments and pits. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of ECA's operations in affected areas.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent or costly construction, drilling, water withdrawal, waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on ECA's operations and financial position. ECA may be unable to pass on increased compliance costs to its customers. Moreover, accidental loss of well control, or releases or spills may occur in the course of ECA's operations, and there can be no assurance that ECA will not incur significant costs and liabilities as a result of such incidents, including any third party claims for damage to property and natural resources or personal injury. While ECA believes that it is in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on it, there is no assurance that this trend will continue in the future.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which ECA's business operations are subject and for which compliance may have a material adverse impact on ECA's capital expenditures, results of operations or financial position.

Hazardous Substances and Wastes. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, ("CERCLA"), also known as the Superfund law and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. ECA generates materials in the course of ECA's operations that may be regulated as hazardous substances.

ECA also generates solid and hazardous wastes that are subject to the requirements of the Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of its operations, ECA generates petroleum hydrocarbon wastes and ordinary industrial wastes that may be classified as hazardous wastes under CERCLA and comparable state laws.

ECA currently owns or leases, and in the past may have owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although ECA may have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by ECA or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes was not under ECA's control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws.

Under these laws, ECA could be required to remove or remediate previously disposed wastes, to clean up contaminated property and to perform remedial operations to prevent future contamination.

Air Emissions. The Clean Air Act, as amended, and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require ECA to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of natural gas projects. On August 16,2012, the EPA published final rules that establish new air emission control requirements for natural gas production, processing and transportation activities, including New Source Performance Standards (NSPS) to address emissions of sulfur dioxide and volatile organic compounds, and National Emission Standards for Hazardous Air Pollutants (NESHAPS) to address hazardous air pollutants. While ECA may be required to incur certain capital expenditures in the next few years for air pollution control equipment or other air emissions-related issues, ECA does not believe that such requirements will have a material adverse effect on its operations.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Accordingly, the EPA has adopted regulations that could trigger permit review for GHG emissions from certain stationary sources. The EPA has also issued regulations that require the establishment and reporting of an inventory of GHG emissions from specified stationary sources, including certain onshore oil and natural gas exploration, development and production facilities. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG gases from, ECA's equipment and operations could require ECA to incur costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the natural gas it produces. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on ECA's assets and operations.

More than one-third of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on ECA's business, financial condition and results of operations.

Water Discharges. The Federal Water Pollution Control Act, as amended ("Clean Water Act"), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the Clean Water Act and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the United States. Any such discharge of pollutants into regulated waters must be performed in accordance with the terms of the permit issued by EPA or the analogous state agency. The Pennsylvania Department of Environmental Protection has adopted a new permitting policy concerning surface water discharges from wastewater treatment facilities handling flowback fluids and produced waters from oil and gas well sites that could result in increased requirements for treatment of these fluids and limitations on their discharge to receiving waters. In April 2011, PADEP called on all Marcellus Shale natural gas drilling operators to voluntarily cease delivering wastewater to centralized wastewater treatment facilities in the state. EPA has announced that it will develop new Clean Water Act effluent guidelines applicable to unconventional oil and gas wastewater, which will establish the process for disposing of wastewater produced from shale gas operations to publicly owned treatment works (POTWs). If ECA is unable to remove and dispose of water at a reasonable cost and within applicable environmental rules, ECA's ability to produce gas commercially and in commercial quantities from the Underlying Properties could be impaired.

Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws, including in Pennsylvania, require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

It is customary to recover natural gas from shale formations, including the Marcellus Shale formation, through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. The U.S. Environmental Protection Agency is continuing to develop its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. The EPA expects to release a draft of the report in late 2014 with a final peer-reviewed report expected in 2016. The results of such a study, once completed, could further spur action towards federal legislation and regulation of hydraulic fracturing activities. The U.S. Bureau of Land Management is still developing its final rule applicable to hydraulic fracturing operations on federal and tribal lands. EPA has also announced that in 2014 it will release its final guidance regarding permitting of hydraulic fracturing operations that use diesel, that it plans to develop proposed rules under Section 8(a) and 8(d) of the Toxic Substances Control Act related to the reporting of chemical substances and mixtures used in hydraulic fracturing, and that it will be developing new Clean Water Act effluent guidelines applicable to unconventional oil and gas wastewater. Some states in which we operate and certain local governments have adopted, and others are considering adopting, regulations that could restrict hydraulic fracturing, including requirements regarding chemical disclosure, well integrity, water sourcing for use in hydraulic fracturing, and baseline testing of nearby water wells. For example, following the passage of the Oil and Gas Amendments of February 14, 2012 or Act 13, the Pennsylvania Department of Environmental Protection (PADEP) enacted new regulations, which among other things require chemical disclosure, increased setbacks, and water management plans. PADEP continues to implement new regulations specifically applicable to the development of unconventional oil and gas wells and has currently proposed new regulations to govern surface use activities. At the local level, some municipalities have considered passing zoning ordinances that would prohibit oil and gas development and hydraulic fracturing in particular. Any increased federal, state or local regulation could increase operational costs and reduce the volumes of oil and natural gas that ECA produces, which would materially adversely affect its revenues and results of operations. An additional level of regulation and permitting of hydraulic fracturing operations at the federal level, could lead to operational delays, increased operating costs and additional regulatory burdens that could make it more difficult for ECA to perform hydraulic fracturing.

Endangered Species Act. The federal Endangered Species Act, as amended ("ESA"), restricts activities that may affect endangered and threatened species or their habitats. While some of ECA's facilities or leased acreage may be located in areas that are designated as habitat for endangered or threatened species, ECA believes that it is in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause ECA to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee Health and Safety. The operations of ECA are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended ("OSHA"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in ECA's operations and that this information be provided to employees, state and local government authorities and citizens. ECA believes that it is in substantial compliance with all applicable laws and regulations relating to worker health and safety.

State regulation. Pennsylvania regulates the drilling for, and the production, gathering, storage, transport and sale of natural gas, including imposing requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells, production rates and the prevention of waste of natural gas resources. Any and all chemicals or other materials involved in the process must be disclosed and approved per statute. The Pennsylvania Department of Environmental Protection is required to impose additional requirements pursuant to the Oil and Gas Amendments of February 14, 2012 discussed elsewhere in this report. The Department is required to employ regulatory agencies such as the Pennsylvania Environmental Quality Board to update existing requirements regarding the drilling, casing, cementing, testing, monitoring and plugging of oil and gas wells, and the protection of water supplies per the February 14, 2012 amendments. PADEP continues to implement new regulations specifically applicable to the development of unconventional gas wells and has currently proposed new regulations to govern surface use activities. The Pennsylvania Public Utility Commission is charged by the recent amendments with enforcement of the gas well impact fees, penalties for nonpayment, and additional requirements resulting from the adoption of the amendments. Proposed regulations and new requirements resulting from the amendments could require ECA to incur increased operating costs. Realized prices are not currently subject to state regulation or subject to other similar direct economic regulation, but there can be no assurance that they will not do so in the future. The effect of these regulations may be to limit the amounts of natural gas that may be produced from ECA's wells and to limit the number of wells or locations ECA can drill.

ECA believes that it is in substantial compliance with all existing environmental laws and regulations applicable to the current operations of the Underlying Properties and that its continued compliance with existing requirements will not have a material adverse effect on the cash distributions to the Trust unitholders. ECA did not incur any material capital expenditures for remediation or pollution control activities for the years ended December 31, 2013 and2012 with respect to the Underlying Properties. Additionally, ECA has informed the Trust that ECA is not aware of any environmental issues or claims that will require material capital expenditures during 2014 with respect to the Underlying Properties. However, there is no assurance that the passage of more stringent laws or implementing regulations in the future will not have a negative impact on the operations of these properties and the cash distributions to the Trust unitholders.

Description of the Trust Units

Each Trust unit is a unit of beneficial interest in the Trust and is entitled to receive cash distributions from the Trust on a pro rata basis, subject to the subordination provisions during the Subordination Period, which ended with the distribution relating to the fourth quarter of 2012, as described elsewhere in this report. The Trust has 17,605,000 common units outstanding, consisting of 13,203,750 originally issued common units and 4,401,250 originally issued subordinated units that automatically converted to common units as of December 31, 2012.

Distributions and Income Computations

Cash distributions to Trust unitholders are made from available funds of the Trust for each calendar quarter. Production payments due to the Trust with respect to any calendar quarter are accrued based on estimated production volumes attributable to the Trust properties during such quarter (as measured at ECA metering systems) and market prices for such volumes. ECA makes a payment to the Trust equal to such accrued amounts within 30 days of the end of each such calendar quarter. After receipt of such payment, 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, reduced by any net increases to reserves. Any difference between the payment made by ECA to the Trust with respect to a calendar quarter and the actual cash production payments relative to the Trust properties received by ECA will be netted to or against future payments by ECA to the Trust.

The amount of available funds for distribution each quarter is payable to the Trust unitholders of record on or about the 45th day following the end of such calendar quarter or such later date as the Trustee determines is required to comply with legal or stock exchange requirements. The Trust distributes available cash on or about the 60th day (or the next succeeding business day following such day if such day is not a business day) following such calendar quarter to each person who was a Trust unitholder of record on the quarterly record date.

Unless otherwise advised by counsel or the IRS, the Trustee will treat the income and expenses of the Trust for each month as belonging to the Trust unitholders of record on the first business day of the month.

Transfer of Trust Units

Trust unitholders may transfer their Trust units in accordance with the Trust Agreement. The Trustee does not require either the transferor or transferee to pay a service charge for any transfer of a Trust unit. The Trustee may require payment of any tax or other governmental charge imposed for a transfer. The Trustee may treat the owner of any Trust unit as shown by its records as the owner of the Trust unit. The Trustee will not be considered to know about any claim or demand on a Trust unit by any party except the record owner. A person who acquires a Trust unit after any quarterly record date will not be entitled to any distribution relating to that quarterly record date. Delaware law governs 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 that Trust unitholders need to correctly report their share of the income and deductions of the Trust. The Trustee also causes to be prepared and filed reports required to be filed under the Securities Exchange Act of 1934, as amended, and by the rules of the New York Stock Exchange.

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

Liability of Trust Unitholders

Under the Delaware Statutory Trust Act, Trust unitholders will be entitled to the same limitation of personal liability extended to stockholders of private corporations for profit under the General Corporation Law of the State of Delaware. No assurance can be given, however, that 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 will be responsible for all costs associated with calling a meeting of Trust unitholders unless such meeting is called by the Trust unitholders, in which case the Trust unitholders will be responsible for all costs associated with calling such meeting of Trust unitholders. Meetings must be held in such location as is designated by the Trustee in the notice of such meeting. The Trustee must send written notice of the time and place of the meeting and the matters to be acted upon to all of the Trust unitholders at least 20 days and not more than 60 days before the meeting. Trust unitholders representing a majority of Trust units outstanding must be present or represented to have a quorum. Each Trust unitholder is entitled to one vote for each Trust unit owned.

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 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. The affirmative vote of the holders of a majority of the outstanding Trust units is required to:

- dissolve the Trust (except in accordance with its terms);
- remove the Trustee or the Delaware Trustee;
- amend the Trust Agreement, the royalty conveyances, the Administrative Services Agreement, the Development Agreement, the Royalty Interest Lien and the hedge agreements (except with respect to certain matters that do not adversely affect the right of Trust unitholders in any material respect);
- merge or consolidate the Trust with or into another entity; or
- approve the sale of all or any material part of the assets of the Trust,

except that if any of the matters listed above (except removal of the Trustee or the Delaware Trustee) would result in a materially disproportionate benefit to ECA or its affiliates compared to other owners of common units, the affirmative vote of the holders of a majority of common units and a majority of Trust units is required.

In addition, 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 ECA in conjunction with its sale of Underlying Properties.

Description of the Trust Agreement

The Trust was created under Delaware law to acquire and hold the Royalty Interests for the benefit of the Trust unitholders pursuant to an agreement between ECA, 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 ECA 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.

The Trust Agreement provides that the Trust's business activities are limited 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 the natural gas hedging contracts relating to, at the formation of the Trust, an estimated 50% of the Trust's royalty production for a term ending March 31, 2014. As a result, the Trust is not permitted to acquire other oil and gas properties or royalty interests. The Trust is not able to issue any additional Trust units.

Duties and Powers of the Trustee

The duties 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 Trustee's principal duties consist of:

- collecting cash attributable to the Royalty Interests;
- paying expenses, charges and obligations of the Trust from the Trust's assets;
- making cash distributions to the unitholders;
- causing to be prepared and distributed a Schedule K-1 for each Trust unitholder and preparing and filing tax returns on behalf of the Trust; and
- causing to be prepared and filed reports required to be filed under the Securities Exchange Act of 1934, as amended, and by the rules of any securities exchange or quotation system on which the Trust units are listed or admitted to trading.

If a Trust liability is contingent or uncertain in amount or not yet currently due and payable, the Trustee may create a cash reserve to pay for the liability. If the Trustee determines that the cash on hand and the cash to be received are insufficient to cover the Trust's liability, the Trust may borrow funds required to pay the liabilities. The Trust may borrow the funds from any person, including the Trustee or its affiliates. The terms of such indebtedness, if funds were loaned by the entity serving as Trustee or Delaware Trustee, would be similar to the terms which such entity would grant to a similarly situated commercial customer with whom it did not have a fiduciary relationship, 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 Trustee borrows funds, the Trust unitholders will not receive distributions until the borrowed funds are repaid.

Responsibility and Liability of the Trustee

The duties and liabilities of the Trustee are set forth in the Trust Agreement. The Trust Agreement provides that (i) the Trustee shall not have any duties or liabilities, including fiduciary duties, except as expressly set forth in the Trust Agreement, and (ii) 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 does not make business decisions affecting the assets of the Trust, and the Trustee's functions under the Trust Agreement are ministerial in nature. In discharging its duty to Trust unitholders, the Trustee may act in its discretion and will be liable to the Trust unitholders only for fraud, gross negligence or acts or omissions constituting bad faith. The Trustee will not be liable for any act or omission of its agents or employees unless the Trustee acted with fraud, in bad faith or with gross negligence in their 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 fraud, gross negligence or bad faith. The Trustee has a lien on the assets of the Trust as security for this indemnification and its compensation as Trustee.

Assets of the Trust

The assets of the Trust consist of the Royalty Interests, natural gas hedging contracts, the Administrative Services Agreement, the Development Agreement, and any cash and temporary investments being held for the payment of expenses and liabilities and for distribution to the Trust unitholders.

Liabilities of the Trust

Because the Trust does not conduct an active business and the Trustee has little power to incur obligations, it is expected that the Trust will incur liabilities only for routine administrative expenses, such as the Trustee's fees and accounting, engineering, legal, tax advisory and other professional fees.

Fees and Expenses

The Trust is responsible for paying all legal, accounting, tax advisory, engineering, printing and other administrative and out-of-pocket expenses incurred by or at the direction of the Trustee or the Delaware Trustee. The Trust is also responsible for paying expenses of tax returns and Schedule K-1 preparation and distribution, as well as expenses incurred as a result of its being a publicly traded entity, including costs associated with annual and quarterly reports to unitholders, independent auditor fees and registrar and transfer agent fees.

Duration of the Trust; Sale of Royalty Interests

The Trust will remain in existence until the Termination Date, which is March 31, 2030. The Trust will dissolve prior to the Termination Date if:

- the Trust sells all of the Royalty Interests;
- gross proceeds attributable to the Royalty Interests are less than $1.5 million for any four consecutive quarters;
- the holders of a majority of the outstanding Trust units vote in favor of dissolution; or
- the Trust is judicially dissolved.

The Trustee would then 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.

ECA's Right of First Refusal

ECA has a right of first refusal to purchase the Perpetual Royalty Interests at the Termination Date. This right of first refusal provides that the Trustee will use commercially reasonable efforts to retain a third-party advisor to market the Perpetual Royalty Interests within 30 business days of the Termination Date. If the Trustee receives a bid from a proposed purchaser other than ECA, prior to selling all or part of the Perpetual Royalty Interests, it will be required to give notice (the "Offer Notice") to ECA, identifying the proposed purchaser and setting forth the proposed sale price, payment terms and other material terms of the proposed sale. ECA would then have 30 days from receipt of the Offer Notice to elect, by notice to the Trustee, to purchase the subject properties offered for sale on the terms and conditions set forth in the Offer Notice. If ECA makes such election, the proposed purchaser would be entitled to receive reimbursement of its reasonable and documented expenses incurred in connection with its review and analysis of the subject properties and bid preparation. ECA and the Trust would share equally the cost of reimbursement to the proposed purchaser.

If ECA does not give notice within the 30-day period following the Offer Notice, the Trust may sell such properties to the identified purchaser on terms and conditions that are substantially the same as those previously set forth in such Offer Notice.

If, after a reasonable marketing period, no bid is received on any or all of the Perpetual Royalty Interests from any party other than ECA, then, as a condition to the sale, ECA shall obtain, at the Trust's expense, and deliver to the Trustee, a fairness opinion from a nationally-recognized valuation firm with expertise in fairness opinions stating that the proposed sale price to be paid by ECA to the Trust for the properties is fair to the Trust.

Federal Income Tax Considerations

The Trust's federal income tax reporting position is that it should be classified as a partnership for federal and applicable state income tax purposes. This position relies on the opinion of counsel to ECA 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 will be 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 Trust's prospectus ("the Prospectus") filed with the SEC pursuant to Rule 424(b) under the Securities Act of 1933, as amended, on July 1, 2010 in connection with the offering of its common units to the public (the "Federal Income Tax Considerations Section in the Prospectus"). However, as discussed in detail below under Item 1A. Risk Factors—Tax Risks Related to the Trust's Common Units, the Trust has not requested a ruling from the IRS regarding its United States federal income tax reporting positions and its positions may not be sustained by a court or if contested by the IRS. Additional information regarding the opinion and tax matters is discussed in the Federal Income Tax Considerations Section in the Prospectus.

Miscellaneous

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

The Delaware Trustee and the Trustee may resign at any time or be removed with or without cause at any time by a vote of not less than a majority of the outstanding Trust units. 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***

Natural gas prices fluctuate due to a number of factors that are beyond the control of the Trust and ECA, and lower prices could reduce proceeds to the Trust and cash distributions to unitholders.

The Trust's reserves and quarterly cash distributions are highly dependent upon the prices realized from the sale of natural gas. Natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and ECA. These factors include, among others:

- weather conditions and seasonal trends;
- regional, domestic and foreign supply and perceptions of supply of natural gas;
- availability of imported liquefied natural gas, or LNG;
- the level of demand and perceptions of demand for natural gas;
- anticipated future prices of natural gas, LNG and other commodities;
- technological advances affecting energy consumption and energy supply;
- U.S. and worldwide political and economic conditions;

- the price and availability of alternative fuels;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- the volatility and uncertainty of regional pricing differentials;
- acts of force majeure;
- governmental regulations and taxation; and
- energy conservation and environmental measures.

Lower natural gas prices will reduce proceeds to which the Trust is entitled and may ultimately reduce the amount of natural gas that is economic to produce from the Underlying Properties. As a result, the operator of any of the Underlying Properties could determine during periods of low gas prices to shut in or curtail production from wells on the Underlying Properties. In addition, the operator of the Underlying Properties could determine during periods of low gas prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, ECA may abandon any well or property if it reasonably believes that the well or property can no longer produce natural gas in commercially economic quantities. This could result in termination of the portion of the royalty interest relating to the abandoned well or property, and ECA would have no obligation to drill a replacement well. In making such decisions, ECA is required under the applicable conveyance to act as a reasonably prudent operator in the AMI under the same or similar circumstances as it would act if it were acting with respect to its own properties, disregarding the existence of the Royalty Interests as burdens affecting such property. The volatility of natural gas prices also reduces the accuracy of estimates of future cash distributions to Trust unitholders.

Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the Trust and the value of the Trust units.

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 reserves estimated to be attributable to the Trust's Royalty Interests. The Trust's reserve quantities and revenues are based on estimates of reserve quantities and revenues for the Underlying Properties. See "The underlying properties—Natural gas reserves" of the Prospectus for a discussion of the method of allocating Proved reserves to the Trust. It is not possible to measure underground accumulations of natural gas in an exact way, and estimating reserves is inherently uncertain. Ultimately, actual production and revenues for the Underlying Properties could vary negatively and in material amounts from estimates and those variations could be material. Petroleum engineers are required to make subjective estimates of underground accumulations of natural gas based on factors and assumptions that include:

- historical production from the area compared with production rates from other producing areas;
- natural gas prices, production levels, Btu content, production expenses, transportation costs, severance and excise taxes and capital expenditures; and
- the assumed effect of governmental regulation.

Changes in these assumptions or actual production costs incurred and results of actual development and production costs could materially decrease reserve estimates.

In particular, 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. The Producing Wells have been operational for less than four and a half years, and many of the PUD Wells have been operational for less than two years. Furthermore, the use of horizontal drilling methods on the Underlying Properties is a recent development in the Marcellus Shale, with ECA commencing the drilling of its first horizontal well in the Marcellus Shale in 2007. The lack of operational history for horizontal wells in the Marcellus Shale formation may also contribute to the inaccuracy of estimates of Proved reserves. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates, including variances attributable to a lack of production history within the Marcellus Shale formation, 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.

The generation of proceeds for distribution by the Trust depends in part on gathering, transportation and processing facilities owned by ECA and others. Any limitation in the availability of those facilities could interfere with sales of natural gas production from the Underlying Properties.

The amount of natural gas that may be produced and sold from any well to which the Underlying Properties relate is subject to curtailment in certain circumstances, such as by reason of weather conditions, pipeline interruptions due to scheduled and unscheduled maintenance, failure of tendered gas to meet quality specifications of gathering lines or downstream transporters, excessive line pressure which prevents delivery of gas, physical damage to the gathering system or transportation system or lack of contracted capacity on such systems. The curtailments may vary from a few days to several months. In many cases, ECA is provided limited notice, if any, as to when production will be curtailed and the duration of such curtailments. If ECA 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.

The generation of proceeds for distribution by the Trust depends in part on the ability of ECA and/or its customers to obtain service on transportation facilities owned by third party pipelines; any limitation in the availability of those facilities and/or any increase in the cost of service on those facilities could interfere with sales of natural gas production from the Underlying Properties.

Natural gas that is gathered on the Greene County Gathering System, including natural gas produced from the Underlying Properties, is currently shipped on two interstate natural gas transportation pipelines. ECA or its purchasers have contracted with those pipelines for firm or interruptible transportation service. The rates for service on the transportation pipelines are regulated by the Federal Energy Regulatory Commission ("FERC") and are subject to increase if the pipeline demonstrates that the existing rates are unjust and unreasonable.

ECA has an agreement with Columbia Gas Transmission, LLC to provide firm transportation downstream of ECA's Greene County Gathering System for 50,000 MMBtu per day. This firm transportation arrangement, which terminates July 31, 2021, has been in effect since August 1, 2011 and is at Columbia Gas Transmission, LLC's filed tariff rate, which initially equated to $0.1996 per MMBtu at one hundred percent load factor. As a result of a filing by Columbia Gas Transmission, LLC with the Federal Energy Regulatory Commission (FERC Docket No. RP12-1021-000), the filed tariff rate was reduced to $0.1878 per MMBtu at a one hundred percent load factor retroactively to January 1, 2012, and, in 2013, the Trust received $0.3 million as its proportionate share of the related refund. This firm transportation is an additional post-production cost and the Trust bears its proportionate share of such costs.

ECA may, in the future, seek to obtain additional firm transportation capacity, but there can be no assurance that capacity will be available. In addition, to the extent ECA's customers or ECA became dependent on interruptible service, and to the extent that either pipeline receives requests for service that exceed the capacity of the pipeline, the pipeline will honor requests by its firm customers first, and will then allocate remaining capacity, if any, to interruptible shippers. As a result, ECA or its customers may be unable to obtain all or a part of any requested interruptible capacity service on the transportation pipelines. Any inability of ECA or its customers to procure sufficient capacity to transport the natural gas gathered on the Greene County Gathering System will decrease and/or delay the receipt of any proceeds that may be associated with natural gas production from wells on the Underlying Properties. In addition, any increase in transportation rates paid by ECA for production attributable to the Trust's interests will decrease the proceeds received by the Trust.

Due to the Trust's lack of industry and geographic diversification, adverse developments in the Trust's existing area of operation could adversely impact its financial condition, results of operations and cash flows and reduce its ability to make distributions to the unitholders.

The Underlying Properties will be operated for natural gas production only and are focused exclusively in the Marcellus Shale formation in Greene County, Pennsylvania. In particular, the concentration of the Underlying Properties in the Marcellus Shale formation in Greene County, Pennsylvania 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 natural gas market or the area of the Underlying Properties could have a significantly greater impact on the Trust's financial condition, results of operations and cash flows than if the Trust's Royalty Interests were more diversified.

The Trust units may lose value as a result of title deficiencies with respect to the Underlying Properties.

The existence of a material title deficiency with respect to the Underlying Properties can reduce the value or render a property worthless, thus adversely affecting the distributions to unitholders. ECA does not obtain title insurance covering mineral leaseholds. Additionally, undeveloped acreage has greater risk of title defects than developed acreage.

Prior to the drilling of the PUD Wells, ECA obtained preliminary title reviews to ensure there were no obvious defects in title to the leasehold. However, a title review is not title insurance, and in the event of such a material title problem in the future, proceeds available for distribution to unitholders and the value of the Trust units may be reduced.

The Trust is passive in nature and has no stockholder voting rights in ECA, managerial, contractual or other ability to influence ECA, or control over the field operations of, sale of natural gas from, or development of, the Underlying Properties.

Trust unitholders have no voting rights with respect to ECA and therefore will have no managerial, contractual or other ability to influence ECA's activities or operations of the gas properties. In addition, pursuant to the Administrative Services Agreement and the Development Agreement, ECA may now transfer operations of any or all of the Trust properties. Such third-party operators may not have the operational expertise of ECA within the AMI. 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 working interests in the property designate one of the interest owners to be the operator of the property. Under these arrangements, the operator is typically responsible for making all decisions relating to drilling activities, sale of production, compliance with regulatory requirements and other matters that affect the property. Neither the Trustee nor the Trust unitholders has any contractual ability to influence or control the field operations of, sale of natural gas from, or future development of, the Underlying Properties. The Trust units are a passive investment that entitles the Trust unitholder to only receive cash distributions from the Royalty Interests and hedging contracts that have been established for the benefit of the Trust.

ECA may sell all or a portion of the Underlying Properties, subject to and burdened by the Royalty Interests, and any such purchaser could have a weaker financial position and/or be less experienced in natural gas development and production than ECA.

Trust unitholders will not be entitled to vote on any sale of the Underlying Properties if the Underlying Properties are sold subject to and burdened by the Royalty Interests and the Trust will not receive any proceeds from any such sale. The purchaser would be responsible for all of ECA's obligations relating to the Royalty Interests on the portion of the Underlying Properties sold, and ECA would have no continuing obligation to the Trust for those properties. Additionally, ECA may enter into farmout or joint venture arrangements with respect to the wells burdened by the Royalty Interests. Any purchaser, farmout counterparty or joint venture partner could have a weaker financial position and/or be less experienced in natural gas development and production than ECA.

The natural gas reserves estimated to be attributable to the Underlying Properties of the Trust are depleting assets and production from those reserves will diminish over time. Furthermore, the Trust is precluded from acquiring other oil and gas properties or Royalty Interests to replace the depleting assets and production.

The proceeds payable to the Trust from the Royalty Interests are derived from the sale of the production of natural gas from the Underlying Properties. The natural gas reserves attributable to the Underlying Properties are depleting assets, which means that the reserves of natural gas attributable to the Underlying Properties will decline over time. As a result, the quantity of natural gas produced from the Underlying Properties will decline over time. Based on the estimated production volumes in the original reserve report described in the Prospectus, the gas production from proved producing reserves attributable to the PDP Royalty Interest was projected to decline at an average rate of approximately 8.5% per year over the life of the Trust. With respect to the PUD Wells, as of the Trust formation date, the production rate was expected to decline approximately 37.3% during the first year of production, approximately 14.7% during the next three to five years of production and approximately 8.0% per year for the remainder of the economically productive life of the well. These production characteristics were generally consistent with other development wells in the AMI. The anticipated rate of decline as originally projected was an estimate and actual decline rates may vary from those estimates. The average decline rate for the 27 PUD Wells for which ECA now has at least 24 months of production data was approximately 43.7% during the first year.

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 natural gas. ECA has no contractual obligation to make capital expenditures on the Underlying Properties in the future. Furthermore, for properties on which ECA is not designated as the operator, ECA has no control over the timing or amount of those capital expenditures. ECA also has the right to non-consent and not participate in the capital expenditures on properties for which it is not the operator, in which case ECA and the Trust will not receive the production resulting from such capital expenditures. If ECA 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 ECA or estimated in the reserve report.

The Trust Agreement provides that the Trust's business activities are limited 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. As a result, the Trust is not permitted to acquire other oil and gas properties or royalty interests to replace the depleting assets and production attributable to the Trust.

The amount of cash available for distribution by the Trust will be reduced by the amount of post-production costs, applicable taxes associated with the Trust's interest, and Trust expenses.

The Royalty Interests and the Trust bear certain costs and expenses that 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 those described below.

- Substantially all of the production from the Producing Wells and the PUD Wells utilize the Greene County Gathering System. The Trust pays the initial Post-Production Services Fee to ECA for use of such system, which includes ECA's costs to gather, compress, transport, process, treat, dehydrate and market the gas. This fee is fixed until ECA's obligation to drill the PUD Wells is satisfied; thereafter, ECA may increase this fee to the extent necessary to recover certain capital expenditures on the Greene County Gathering System, provided the resulting charge does not exceed the prevailing charges in the area for similar services. Additionally, the Trust is charged for the cost of fuel used in the compression process or equivalent electricity charges when electric compressors are used.

- Any third party post-production costs incurred in the future and associated with the Trust's interests will reduce cash received by or available for distribution, including any amounts paid by ECA for transportation on downstream interstate pipelines. Such post-production costs will include the costs to be incurred in connection with the agreement ECA has entered into with a third party to obtain firm transportation downstream of ECA's Greene County Gathering System for 50,000 MMBtu per day at the third party's filed tariff rate, which equates to $0.1878 per MMBtu at a one hundred percent load factor. The rate is subject to adjustments, which may be retroactive, by regulatory authorities.

- Taxes allocated to or imposed on the Trust include Pennsylvania franchise tax and any applicable property, ad valorem, production, severance, excise and other similar taxes. Currently, there are no taxes in Pennsylvania related to the production or severance of oil and natural gas in Pennsylvania, but previously there were proposals in both the Pennsylvania Senate Finance and the House Energy and Environmental Resources Committees, which was not adopted, to enact a severance tax, and lawmakers may propose other taxes in the future. If adopted, such taxes would be a post-production cost that is borne by the Trust.

- The Trust bears 100% of Trust administrative expenses, including fees paid to the Trustee and the Delaware Trustee and an annual administrative services fee of $60,000 payable to ECA.

- The Trust is also responsible for paying other expenses, including costs associated with annual and quarterly reports to unitholders, tax return and Schedule K-1 preparation and distribution, independent auditor fees and registrar and transfer agent fees.

The amount of costs and expenses that will be borne by the Trust may vary materially from quarter-to-quarter. The extent by which the costs and expenses described above 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.

A decrease in the differential between the price realized by ECA for natural gas produced from the Underlying Properties and the NYMEX or other benchmark price of 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 ECA's natural gas production have historically exceeded the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions, although, during 2013, the prices received were often lower than the benchmark prices and there is no assurance that this will not continue to be the case in the future. The difference between the price received and the benchmark price is called a basis differential. The differential may vary significantly due to market conditions, the quality and location of production and other factors. ECA cannot accurately predict natural gas differentials. Further decreases in the differential between the realized price of natural gas and the benchmark price for natural gas could reduce the proceeds to the Trust and therefore the cash distributions by the Trust and the value of the Trust units.

ECA has entered into natural gas floor price contracts for the benefit of the Trust that cover only a portion of the estimated natural gas production attributable to the Royalty Interests, and such hedging arrangements will terminate after March 31, 2014. The Trust's receipt of any payments due based on these natural gas hedging contracts depends upon the financial position of the hedge contract counterparties. A default by any of the hedge contract counterparties could reduce the amount of cash available for distribution to the Trust unitholders.

At the formation of the Trust, approximately fifty percent of the estimated natural gas production attributable to the Royalty Interests was hedged from April 1, 2010 through March 31, 2014. As a result, the remaining 50% of estimated production through March 31, 2014 is not, and all production after such date will not be, hedged to protect against the price risks inherent in holding interests in natural gas, a commodity that is frequently characterized by significant price volatility. The Trust's counterparties under the natural gas floor price contracts are Wells Fargo Capital Finance Inc. and BP Energy Company. In the event that any of the counterparties to the natural gas hedging contracts default on their obligations to make payments to the Trust under the hedge contracts, the cash distributions to the Trust unitholders would likely be materially reduced as the hedge payments are intended to provide additional cash to the Trust during periods of lower natural gas prices. ECA has no continuing obligation with respect to the natural gas floor price contracts.

Natural gas wells are subject to operational hazards that can cause substantial losses. ECA maintains insurance; however, ECA may not be adequately insured for all such hazards.

There are a variety of operating risks inherent in natural gas production and associated activities, such as fires, leaks, explosions, mechanical problems, major equipment failures, blow-outs, uncontrollable flow of natural gas, water or drilling fluids, casing collapses, abnormally pressurized formations and natural disasters. The occurrence of any of these or similar accidents that temporarily or permanently halt the production and sale of natural gas at any of the Underlying Properties will reduce Trust distributions by reducing the amount of proceeds available for distribution.

Additionally, if any of such risks or similar accidents occur, ECA could incur substantial losses as a result of injury or loss of life, severe damage or destruction of property, natural resources and equipment, regulatory investigation and penalties and environmental damage and clean-up responsibility. If ECA experiences any of these problems, its ability to conduct operations and perform its obligations to the Trust could be adversely affected. While ECA maintains insurance coverage it deems appropriate for these risks with respect to the Underlying Properties, ECA's operations may result in liabilities exceeding such insurance coverage or liabilities not covered by insurance. If a well is damaged, ECA would have no obligation to drill a replacement well or make the Trust whole for the loss. The Trust does not maintain any type of insurance against any of the risks of conducting oil and gas exploration and production or related activities.

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

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 the gross proceeds to the Trust attributable to the Royalty Interests and hedge agreements (after deducting any amounts owed to ECA pursuant to the natural gas swap agreements) are less than $1.5 million for any four consecutive quarters. Sale of all the Royalty Interests will result in the dissolution of the Trust. The net proceeds of any such sale will be distributed to the Trust unitholders. The Trust will begin to liquidate on the Termination Date. The Trust unitholders will not be entitled to receive any proceeds from the sale of production from the Underlying Properties following such date. The Term Royalty Interests will automatically revert to ECA at the Termination Date, while the Perpetual Royalty Interests will be sold and the proceeds will be distributed to the unitholders (including ECA to the extent of any Trust units it owns) at the Termination Date or soon thereafter. ECA will have a right of first refusal to purchase the Perpetual Royalty Interests at the Termination Date.

ECA and the Private Investors may sell additional Trust units, and such sales could have an adverse effect on the trading price of the common units.

As of December 31, 2013, ECA held a total of 2,268,401 common units. Private Investors held some of the common units they held immediately after the Trust's offering. All of the subordinated units automatically converted into common units at the end of the Subordination Period, which occurred on December 31, 2012. The Trust granted registration rights to ECA and the Private Investors which would facilitate sales of common units by such holders. During 2011 ECA exercised one of its demand rights under the registration rights agreement in connection with a firm commitment underwritten offering by ECA of 2,525,000 common units. Pursuant to this agreement, during the quarter ended June 30, 2011, ECA sold 2,525,000 common units in a secondary public offering and an additional 181,175 common units pursuant to the overallotment option. Two of the Private Investors exercised the two remaining registration rights during 2012, and the Trust filed registration statements on Forms S-3 and S-4 as a result of those demands, both of which have been declared effective. In March 2013, ECA announced an exchange offer for Depositary Units of Eastern American Natural Gas Trust ("NGT Depositary Units"). 946,000 NGT Depositary Units were validly tendered for exchange and ECA delivered, in the exchange offer, 1,288,456 Trust common units which reduced ECA's beneficial ownership to an aggregate of 2,936,942 common units. During the year ended December 31, 2013, ECA also disposed of, through transfer or sale, 630,990 common units. Additional sales by ECA or the Private Investors could have an adverse effect on the trading price of the common units.

Conflicts of interest could arise between ECA and the Trust unitholders.

As a working interest owner in the Underlying Properties, ECA could have interests that conflict with the interests of the Trust and the Trust unitholders. For example:

- ECA's interests may conflict with those of the Trust and the Trust unitholders in situations involving the development, maintenance, operation or abandonment of the Underlying Properties. Additionally, ECA may abandon a well which is uneconomic to it while such well is still generating revenue for the Trust unitholders. ECA may make decisions with respect to expenditures and decisions to allocate resources on projects in other areas that adversely affect the Underlying Properties, including reducing expenditures on these properties, which could cause gas production to decline at a faster rate and thereby result in lower cash distributions by the Trust in the future. In making such decisions, ECA is required under the applicable conveyance to act as a reasonably prudent operator in the AMI under the same or similar circumstances as it would act if it were acting with respect to its own properties, disregarding the existence of the royalty interests as burdens affecting such property.
- ECA may sell some or all of the Underlying Properties. Any such sale may not be in the best interests of the Trust unitholders. Any purchaser may lack ECA's experience in the Marcellus Shale or its credit worthiness.
- ECA may, without the consent of the Trust unitholders, require the Trust to release Royalty Interests with an aggregate value to the Trust of up to $5.0 million during any 12-month period.

These releases will be made only in connection with the sale by ECA of the Underlying Properties and are conditioned upon the Trust receiving an amount equal to the fair value to the Trust of such Royalty Interests. See "Sale and Abandonment of Underlying Properties" in Item 2 of this report.

- ECA may in its discretion increase its Post-Production Services Fee for post-production costs on the Greene County Gathering System to the extent necessary to recover certain capital expenditures on the Greene County Gathering System.

- ECA is permitted under the conveyance agreements creating the Royalty Interests to enter into new processing and transportation contracts without obtaining bids from or otherwise negotiating with any independent third parties, and ECA will deduct from the Trust's proceeds any charges under such contracts attributable to production from the Trust properties. Provisions in the conveyance agreements, however, require that charges under future contracts with affiliates of ECA relating to processing or transportation of natural gas must be comparable to charges prevailing in the area for similar services.

- ECA can sell its units without considering the effects such sale may have on common unit prices or on the Trust itself. Additionally, ECA can vote its Trust units in its sole discretion.

The Trust is administered by a Trustee who cannot be replaced except at a special meeting of Trust unitholders.

The business and affairs of the Trust are administered by the Trustee. Voting rights of Trust unitholders are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Trust unitholders or for an annual or other periodic re-election of the Trustee. The Trust Agreement provides that the Trustee may only be removed and replaced by the holders of a majority of the outstanding Trust units, including Trust units held by ECA, at a special meeting of Trust unitholders called by either the Trustee or the holders of not less than 10% of the outstanding Trust units. As a result, it will be difficult for public unitholders to remove or replace the Trustee without the cooperation of ECA (so long as it holds a significant percentage of total Trust units) or other holders of a substantial percentage of the outstanding Trust units.

Trust unitholders have limited ability to enforce provisions of the Royalty Interests, and ECA's liability to the Trust is limited.

The Trust Agreement permits the Trustee and the Trust to sue ECA or any other future owner of the Underlying Properties to enforce the terms of the conveyances creating the PDP and PUD Royalty Interests. If the Trustee does not take appropriate action to enforce provisions of these conveyances, Trust unitholders' recourse would be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. The Trust Agreement expressly limits a Trust unitholder's ability to directly sue ECA or any other third party other than the Trustee. As a result, Trust unitholders will not be able to sue ECA or any future owner of the Underlying Properties to enforce these rights. Furthermore, the Royalty Interest conveyances provide that, except as set forth in the conveyances, ECA 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.

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

Under the Delaware Statutory Trust Act, Trust unitholders will be entitled to the same limitation of personal liability extended to stockholders of corporations 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.

ECA is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting its operations or expose ECA to significant liabilities.

ECA's natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct its operations in compliance with these laws and regulations, ECA must obtain and maintain numerous permits, drilling bonds, approvals and certificates from various federal, state and local governmental authorities and engage in extensive reporting. ECA may incur substantial costs in order to maintain compliance with these existing laws and regulations. Further, in light of the explosion and fire on the drilling rig Deepwater Horizon in the Gulf of Mexico, as well as recent incidents involving the release of natural gas and fluids as a result of drilling activities in the Marcellus Shale, there has been a variety of regulatory initiatives at the federal and state level to restrict oil and gas drilling operations in certain locations. Any increased regulation or suspension of oil and gas exploration and production, or revision or reinterpretation of existing laws and regulations, that arises out of these incidents or otherwise could result in delays and higher operating costs. Such costs or significant delays could have a material adverse effect on ECA's business, financial condition and results of operations. ECA must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent ECA is a shipper on interstate pipelines, it must comply with the tariffs of such pipelines and with federal policies related to the use of interstate capacity.

Laws and regulations governing natural gas exploration and production may also affect production levels. ECA is required to comply with federal and state laws and regulations governing conservation matters, including provisions related to the unitization or pooling of the natural gas properties; the establishment of maximum rates of production from natural gas wells; the spacing of wells; the plugging and abandonment of wells; and removal of related production equipment. These and other laws and regulations can limit the amount of natural gas ECA can produce from its wells, limit the number of wells it can drill, or limit the locations at which it can conduct drilling operations, which in turn could negatively impact Trust distributions, estimated and actual future net revenues to the Trust and estimates of reserves attributable to the Trust's interests.

New laws or regulations, or changes to existing laws or regulations may unfavorably impact ECA, could result in increased operating costs and have a material adverse effect on ECA's financial condition and results of operations. For example, Congress has previously considered legislation that, if adopted in its proposed form, would subject companies involved in natural gas and oil exploration and production activities to, among other items the elimination of most U.S. federal tax incentives and deductions available to natural gas exploration and production activities, and the prohibition or additional regulation of private energy commodity derivative and hedging activities. Additionally, the Pennsylvania Environmental Quality Board has proposed amendments to Pennsylvania's oil and gas regulations to update existing requirements regarding the drilling, casing, cementing, testing, monitoring and plugging of oil and gas wells, and the protection of water supplies, including reporting the list of chemicals used in hydraulic fracturing or to stimulate the well.

Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may require increased capital costs on the part of ECA and third party downstream natural gas transporters. These and other potential regulations could increase ECA's operating costs, reduce ECA's liquidity, delay ECA's operations, increase direct and third party post production costs associated with the Trust's interests or otherwise alter the way ECA conducts its business, which could have a material adverse effect on ECA's financial condition, results of operations and cash flows and which could reduce cash received by or available for distribution, including any amounts paid by ECA for transportation on downstream interstate pipelines.

The ability of ECA to satisfy its obligations to the Trust depends on the financial position of ECA, and in the event of a default by ECA in its obligations to the Trust, or in the event of ECA's bankruptcy, it would be expensive and time-consuming for the Trust to exercise its remedies.

ECA is a privately held, independent energy company engaged in the exploration, development, production, gathering and aggregation and sale of natural gas and oil, primarily in the Appalachian Basin, Gulf Coast and Rocky Mountain regions in the United States and in New Zealand. ECA is also the operator of all of the Producing Wells and all of the PUD Wells. The conveyances also provide that ECA is obligated to market, or cause to be marketed, the natural gas production related to the Underlying Properties. Due to the Trust's reliance on ECA to fulfill these numerous obligations, the value of the Royalty Interests and its ultimate cash available for distribution will be highly dependent on ECA's performance. ECA is not a reporting company and does not file periodic reports with the SEC. Therefore, as a Trust unitholder, you do not have access to financial information of ECA.

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

Due to uncertainty under the laws of Pennsylvania, there is a risk that the Royalty Interests conveyed by ECA to the Trust would not be treated as real property interests, or interests in hydrocarbons in place or to be produced. As a result, the Royalty Interests might be treated as unsecured claims of the Trust against ECA in the event of ECA's bankruptcy. The Royalty Interest Lien is intended to provide security to the Trust should the Royalty Interests be subject to such a challenge. If the PDP Royalty Interest or the PUD Royalty Interest were determined not to be a real property interest owned by the Trust, the Trust's remedy would be to foreclose on the Trust's Royalty Interest Lien to cause the Trust to receive a volume of natural gas production from the Trust properties calculated in accordance with the provisions of the conveyances of the Royalty Interests to the Trust. Foreclosure on the Royalty Interest Lien is exercisable only following a bankruptcy filing of ECA or its successor and based on an uncured payment default occurring under the conveyances of the Royalty Interests to the Trust existing at the time of, or occurring after, such bankruptcy filing. The process of foreclosing to enforce the Royalty Interest Lien would be expensive and time-consuming; and the resulting delays and expenses could reduce Trust distributions substantially or eliminate them for an unpredictable period of time.

The proceeds of the Royalty Interests may be commingled, for a period of time, with proceeds of ECA's retained interest. 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 ECA's retained interest, be able to assert claims to the proceeds that should be delivered to the Trust. In addition, during a bankruptcy of ECA, it is possible that payments of the royalties may be delayed or deferred. It is also possible that the obligation to pay royalties will be disaffirmed or cancelled. In either situation, the Trust may need to look to the Royalty Interest Lien to replace its rights under the Royalty Interests. During the pendency of any bankruptcy proceedings involving ECA, the Trust's ability to foreclose on the Royalty Interest Lien, and the ability to collect cash payments from customers being held in ECA's accounts that are attributable to production from the Trust properties, may be stayed by the bankruptcy court. Delay in realizing on the collateral for the Royalty Interest Lien is possible, and it cannot be guaranteed that a bankruptcy court would permit such foreclosure. It is possible that the bankruptcy would also delay the execution of a new agreement with another driller or operator. If the Trust enters into a new agreement with a drilling or operating partner, the new partner might not achieve the same levels of production or sell natural gas at the same prices as ECA was able to achieve.

The operations of ECA are subject to environmental laws and regulations that may result in significant costs and liabilities.

The natural gas exploration and production operations of ECA in the Marcellus Shale are subject to stringent and comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to ECA's operations including the acquisition of a permit before conducting drilling; water withdrawal or waste disposal activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of ECA's operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of ECA's operations due to its handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to its operations, and as a result of historical industry operations and waste disposal practices. Under certain environmental laws and regulations, ECA could be subject to joint and several strict liability for the removal or remediation of previously released materials or property contamination regardless of whether ECA was responsible for the release or contamination or if the operations were not in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which ECA's wells are drilled and facilities where ECA's petroleum hydrocarbons or wastes are taken for reclamation or disposal may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage or to recover some or all of the costs of the removal or remediation of released materials. In addition, the risk of accidental spills or releases could expose ECA to significant liabilities that could have a material adverse effect on its financial condition or results of operations. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require ECA to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on its results of operations, competitive position or financial condition. ECA may not be able to recover some or any of these costs from insurance.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the natural gas that ECA produces while the physical effects of climate change could disrupt ECA's production and cause ECA to incur significant costs in preparing for or responding to those effects.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present a danger to public health and the environment. These findings allow the agency to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. Accordingly, the EPA has adopted regulations that could trigger permit review for GHG emissions from certain stationary sources. The EPA has also issued regulations that require the establishment and reporting of an inventory of GHG emissions from specified stationary sources, including certain onshore oil and natural gas exploration, development and production facilities. At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of

GHGs. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHGs from, ECA's equipment and operations could require ECA to incur costs to reduce emissions of GHGs associated with its operations or could adversely affect demand for the natural gas that it produces. Finally, it should be noted 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 increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on ECA's assets and operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect ECA's services.

Hydraulic fracturing is an important and commonly used process for the completion of natural gas wells, and to a lesser extent, oil wells, in formations with low permeabilities, such as shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate natural gas production.

Various federal, state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. For instance, the New York Department of Environmental Conservation announced in April 2010 that the watersheds relied upon by New York City and Syracuse as sources of drinking water would be excluded from the pending generic environmental review process, thereby requiring natural gas operators seeking to drill in either of the watersheds, which are located in the Marcellus Shale region, to pursue a case-by-case environmental review to establish whether appropriate measures to mitigate potential impacts can be developed. At the local level, some municipalities have considered passing zoning ordinances that would prohibit oil and gas development and hydraulic fracturing in particular.

The U.S. Environmental Protection Agency is continuing to develop its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. EPA expects to release a draft of the report in late 2014 with a peer-reviewed report expected in 2016. The results of such a study could further spur action towards federal legislation and regulation of hydraulic fracturing activities. If ECA is unable to remove and dispose of water at a reasonable cost and in compliance with applicable environmental rules, ECA's ability to produce gas commercially and in commercial quantities from the Underlying Properties could be impaired.

EPA has also announced that in 2014 it will release its final guidance regarding permitting of hydraulic fracturing operations that use diesel, that it plans to develop proposed rules under Section 8(a) and 8(d) of the Toxic Substances Control Act related to the reporting of chemical substances and mixtures used in hydraulic fracturing, and that it will be developing new Clean Water Act effluent guidelines applicable to unconventional oil and gas wastewater.

On February 14, 2012, Pennsylvania passed Act 13, Amendment Pennsylvania's Oil and Gas Act to require, among other things, additional information in the stimulation record including water source identification and volume as well as a list of chemicals used to stimulate the well, including chemicals used in hydraulic fracturing. The Act requires PADEP to expand its reporting and permitting policy concerning water and chemical additives utilized in the process. Water discharges from wastewater treatment facilities handling flowback fluids and produced waters from oil and gas well sites are currently regulated and being reviewed. The Amendments implemented or require increased requirements for reporting, management, and treatment of these fluids as well as limitations on their discharge to receiving waters, requirements for containment plans for spills and a rebuttable presumption of liability for contamination of water supply near unconventional wells. Increased distances for drill pads from property lines and waterways are required as well as required additional notices to municipalities. Impact fees have also been authorized to be imposed on producers. These require additional reporting and payment of fees and any outstanding penalties in order for additional wells to be permitted. As required by Act 13, PADEP continues to implement new regulations specifically applicable to the development of unconventional oil and gas wells and has currently proposed new regulations to govern surface use activities. The adoption of these and any other federal or state laws or regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult for ECA to complete natural gas wells in the Marcellus Shale as well as increase its costs of compliance and doing business.

Tax Risks Related to the Trust's Common Units

The Trust's tax treatment depends on its status as a partnership for United States federal income tax purposes. At the inception of the Trust, the Trust received an opinion from tax counsel that the Trust will be treated as a partnership for United States federal income tax purposes. If the Internal Revenue Service were to treat the Trust as a corporation for United States federal income tax purposes, then its cash available for distribution to you 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 United States federal income tax purposes. At the inception of the Trust, ECA and the Trust received an opinion from tax counsel that the Trust would be treated as a partnership for United States federal income tax purposes. In order for the Trust to be treated as a partnership for United States federal income tax purposes, current law requires that 90% or more of our gross income for every taxable year consist of "qualifying income," as defined in Section 7704 of the Internal Revenue Code. The Trust may not meet this requirement or current law may change so as to cause, in either event, the Trust to be treated as a corporation for United States federal income tax purposes or otherwise subject the Trust to taxation as an entity. Although the Trust does not believe based upon its current activities that it is so treated, a change in current law could cause it to be treated as a corporation for United States federal income tax purposes or otherwise subject it to taxation as an entity. The Trust has not requested, and does not plan to request, a ruling from the Internal Revenue Service, which we referred to as the IRS, on this or any other tax matter affecting it.

If the Trust was treated as a corporation for United States federal income tax purposes, it would pay United States federal income tax on its taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely be required to pay state income tax. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you. Because a tax would be imposed upon the Trust as a corporation, its cash available for distribution to you would be substantially reduced. Therefore, treatment of the Trust as a corporation would result in a material reduction in the anticipated cash flow and after-tax return to you, likely causing a substantial reduction in the value of the Trust units.

The Trust Agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects the Trust to taxation as a corporation or otherwise subjects it to entity-level taxation for United States federal income tax purposes, the target distribution amounts may be adjusted to reflect the impact of that law on the Trust.

If the Trust were subjected to a material amount of additional entity- level taxation by Pennsylvania or any other states, the Trust's cash available for distribution to you would be reduced.

The Trust will be required to pay Pennsylvania franchise tax on its capital stock value, as determined pursuant to the statute and apportioned to Pennsylvania. The current tax rate of 0.089% is currently scheduled to be reduced to 0.067% in 2014 and 0.045% in 2015 and to be completely phased out in 2016. This schedule may be altered and the taxes left in place subject to the General Assembly in its annual budget process. Changes in current state law may subject the Trust to additional entity-level taxation by Pennsylvania or other states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any additional taxes on the Trust may substantially reduce the cash available for distribution to you and, therefore, negatively impact the value of an investment in the Trust units.

The Trust Agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects the Trust to additional amounts of entity-level taxation for state or local income tax purposes, the target distribution amounts may be adjusted to reflect the impact of that law on the Trust.

If enacted, severance taxes in Pennsylvania could materially increase the applicable taxes that are borne by the Trust.

Although Pennsylvania has historically not imposed a severance tax on the production of natural gas, if any future severance tax legislation is adopted, any such severance tax would be a cost that would be borne by the Trust and could materially reduce distributions to unitholders.

The Trust Agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects the Trust to additional amounts of entity-level taxation for state or local income tax purposes, the target distribution amounts may be adjusted to reflect the impact of that law on the Trust.

The tax treatment of publicly traded partnerships or an investment in our Trust units could be affected by recent and potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The current United States federal income tax treatment of publicly traded partnerships, including the Trust, or an investment in the Trust units, may be modified by administrative, legislative or judicial interpretation at any time. For example, members of Congress previously considered substantive changes to the existing United States federal income tax laws that affect certain publicly traded partnerships. Any modification to the United States federal income tax laws or interpretations thereof could make it difficult or impossible to meet the requirements for the Trust to be treated as a partnership for United States federal income tax purposes, affect or cause us to change our business activities, affect the tax considerations of an investment in the Trust, change the character or treatment of portions of the Trust income and adversely affect an investment in the Trust's units. Moreover, any modification to the United States federal income tax laws and interpretations thereof may or may not be applied retroactively. Although the previously proposed legislation would not appear to affect the Trust's tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any potential change in law or interpretation thereof could negatively impact the value of an investment in the Trust units.

Under current law for the taxable year ending December 31, 2013, the highest marginal United States federal income tax rate applicable to ordinary income of individuals is 39.6% and the highest marginal United States federal income tax rate applicable to long-term capital gains (generally, capital gains on certain assets held for more than 12 months) of individuals is 20%. These rates are subject to change by new legislation at any time.

The Patient Protection and Affordable Care Act of 2010, as amended by the Health Care and Education Reconciliation Act of 2010 imposes a 3.8% Medicare tax on certain net investment income from a variety of sources earned by individuals for taxable years beginning after December 31, 2012. For these purposes, net investment income generally includes a Trust unitholder's allocable share of the Trust income and gain realized by a Trust unitholder from a sale of the Trust units. The tax will be imposed on the lesser of (i) the Trust unitholder's net income from all investments, or (ii) the amount by which the Trust unitholder's adjusted gross income exceeds $250,000 (if the Trust unitholder is married and filing jointly) or $200,000 (if the Trust unitholder is unmarried).

The Trust prorates items of income, gain, loss and deduction between transferors and transferees of the Trust units each month based upon the ownership of the Trust units on the first day of each month, instead of on the basis of the date a particular unit is transferred .

The Trust prorates items of income, gain, loss and deduction between transferors and transferees of the Trust units each month based upon the ownership of the Trust units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The use of this proration method may not be permitted under existing Treasury Regulations, and, accordingly, the Trust's counsel was unable to opine as to the validity of this method. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among the Trust unitholders. If the IRS contests the federal income tax positions the Trust takes, the market for the Trust units may be adversely impacted, the cost of any IRS contest will reduce the Trust's cash available for distribution to you and items of income, gain, loss and deduction may be reallocated among Trust unitholders.

If the IRS contests the United States federal income tax positions the Trust takes, the market for the Trust units may be adversely impacted and the cost of any IRS contest will reduce the Trust's cash available for distribution to you.

The Trust has not requested a ruling from the IRS with respect to its treatment as a partnership for United States 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 Prospectus or from the positions the Trust takes. It may be necessary to resort to administrative or court proceedings to attempt to sustain some or all of the conclusions of the Trust's counsel or the positions the Trust takes. A court may not agree with some or all of the conclusions of the Trust's counsel or positions the Trust takes. Any contest with the IRS may materially and adversely impact the market for the Trust units and the price at which they trade. In addition, the Trust's costs of any contest with the IRS will be borne indirectly by the Trust unitholders because the costs will reduce the Trust's cash available for distribution.

You will be required to pay taxes on your share of the Trust's income even if you do not receive any cash distributions from the Trust.

Because the Trust unitholders will be treated as partners to whom the Trust will allocate taxable income which could be different in amount than the cash the Trust distributes, you will be required to pay any United States federal income taxes and, in some cases, state and local income taxes on your share of the Trust's taxable income even if you receive no cash distributions from the Trust. You may not receive cash distributions from the Trust equal to your share of the Trust's taxable income or even equal to the actual tax liability that result from that income.

Tax gain or loss on the disposition of the Trust units could be more or less than expected.

If you sell your Trust units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those Trust units. Because distributions in excess of your allocable share of the Trust's net taxable income decrease your tax basis in your Trust units, the amount, if any, of such prior excess distributions with respect to the Trust units you sell will, in effect, become taxable income to you if you sell such Trust units at a price greater than your tax basis in those Trust units, even if the price you receive is less than your original cost. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion recapture.

Tax-exempt entities and non-United States 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-United States persons raises issues unique to them. For example, some of the Trust income allocated to organizations exempt from United States federal income tax, including IRAs and other retirement plans, may be unrelated business taxable income which would be taxable to them. Distributions to non-United States persons may be reduced by withholding taxes at the highest applicable effective tax rate, and non-United States persons may be required to file United States federal income tax returns and pay tax on their share of the Trust's taxable income.

The Trust will treat each purchaser of Trust units as having the same economic attributes without regard to the actual Trust units purchased. The IRS may challenge this treatment, which could adversely affect the value of the Trust units.

Due to a number of factors, including the Trust's inability to match transferors and transferees of Trust units, the Trust will adopt positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of Trust units and could have a negative impact on the value of the Trust units or result in audit adjustments to your tax returns.

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, the Trust unitholder may no longer be treated for United States federal income tax purposes as a partner with respect to those Trust units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of the Trust's income, gain, loss or deduction with respect to those Trust units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those Trust units could be fully taxable as ordinary income. The Trust's counsel has not rendered an opinion regarding the treatment of a unitholder where Trust units are loaned to a short seller to cover a short sale of Trust units; therefore, Trust unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from loaning their Trust units.

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

The United States 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. It also could affect the amount of gain from unitholders' sale of Trust units and could have a negative impact on the value of the Trust units or result in audit adjustments to unitholders' tax returns without the benefit of additional deductions.

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

The Trust will be considered to have technically terminated for United States federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in its capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same Trust unit within any 12 month period will be counted only once. The Trust's termination would, among other things, result in the closing of its taxable year for all Trust unitholders, which would result in the Trust filing two tax returns (and the Trust unitholders could receive two Schedules K-1) for one calendar year. The IRS has previously announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be required to provide only a single Schedule K-1 to unitholders for the tax year in which the termination occurs. In the case of a unitholder reporting on a taxable year other than a calendar year ending December 31, the closing of the Trust's taxable year may also result in more than twelve months of the Trust's taxable income being includable in his taxable income for the year of termination. A technical termination would not affect the Trust's classification as a partnership for United States federal income tax purposes, but instead, the Trust would be treated as a new partnership for tax purposes. If treated as a new partnership, the Trust must make new tax elections and could be subject to penalties if the Trust is unable to determine that a technical termination occurred.

Certain United States federal income tax preferences currently available with respect to natural gas production may be eliminated as a result of future legislation.

Among the changes contained in President Obama's Budget Proposal for Fiscal Year 2014 (the "2014 Budget") is the elimination of certain key United States federal income tax preferences relating to natural gas exploration and production. The 2014 Budget proposes to eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources effective in 2014. Specifically, the 2014 Budget proposes to repeal the deduction for percentage depletion with respect to oil and natural gas wells, including interests such as the Perpetual Royalty Interests, in which case only cost depletion would be available.

Item 1B. *Unresolved Staff Comments.*

None.

Item 2. *Properties.*

The Underlying Properties

The Underlying Properties consist of the working interests owned by ECA and the Private Investors in the Marcellus Shale formation in Greene County, Pennsylvania arising under leases and Farmout agreements related to properties from which the PDP Royalty Interest and the PUD Royalty Interest were conveyed. As of December 31, 2013 the total gas reserves attributable to the Trust interests were 60.5 Bcf. ECA continues to be the operator of all of the wells subject to the Royalty Interests although, as of January 1, 2013, it is no longer contractually obligated to the Trust to remain so. The reserves attributable to the Royalty Interests include the reserves that are expected to be produced from the Marcellus Shale formation during the remaining portion of the 20-year period in which the Trust owns the Royalty Interests as well as the residual interest in the reserves that the Trust will sell on or shortly following the Termination Date.

Natural Gas Reserves

Ryder Scott estimated natural gas reserves attributable to the Royalty Interests as of December 31, 2013. Numerous uncertainties are inherent in estimating reserve volumes and values, and the estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of the reserves may vary significantly from the estimates.

Proved reserves of the Royalty Interests. The following table sets forth, certain estimated Proved reserves, estimated future net cash flows and the discounted present value thereof attributable to the Royalty Interests, as of December 31, 2013, in each case derived from the Ryder Scott reserve report. The reserve report was prepared by Ryder Scott in accordance with criteria established by the SEC. In accordance with the SEC's rules, the reserves presented below were determined using the twelve month unweighted arithmetic average of the first-day-of-the-month price for the period from January 1, 2013 through December 31, 2013, without giving effect to any derivative transactions, and were held constant for the life of the properties. This yielded a price for natural gas of $3.70 per Mcf. The net revenues attributable to the Trust's reserves are net of the Trust's obligation to reimburse ECA for the post-production costs. The reserves and cash flows attributable to the Trust's interests include only the reserves attributable to the Underlying Properties that are expected to be produced within the remaining portion of the 20-year period in which the Trust owns the Royalty Interests as well as the residual interest in the reserves that the Trust will own on the Termination Date. A summary of the Ryder Scott reserve report dated December 11, 2013 is included as Appendix A to this report.

Proved reserves	Proved Gas Reserves (Bcf)	Estimated Future Net Cash Flows	Discounted Estimated Future Net Cash Flows(1)
		(Dollars in thousands)	
Royalty Interests:			
Proved Developed	60,453	$ 179,406	$ 88,370

(1) The present values of future net cash flows for the Royalty Interests were determined using a discount rate of 10% per annum.

Information concerning historical changes in net Proved reserves attributable to the Royalty Interests, and the calculation of the standardized measure of discounted future net cash flows related thereto, is contained in the unaudited supplemental information contained elsewhere in this report. The Trust has not filed reserve estimates covering the Royalty Interests with any other federal authority or agency.

The Reserve Report

Technologies. The reserve report was prepared using decline curve analysis to determine the reserves of individual Producing Wells.

Internal Controls. Ryder Scott, the independent petroleum engineering consultant, estimated, in accordance with appropriate engineering, geologic, and evaluation principles and techniques that are in accordance with practices generally accepted in the petroleum industry, and definitions and guidelines established by the SEC, all of the proved reserve information in this report. These reserves estimation methods and techniques are widely taught in university petroleum curricula and throughout the industry's ongoing training programs. Although these appropriate engineering, geologic, and evaluation principles and techniques that are in accordance with practices generally accepted in the petroleum industry are based upon established scientific concepts, the application of such principles involves extensive judgment and is subject to changes in existing knowledge and technology, economic conditions and applicable statutory and regulatory provisions. These same industry wide applied techniques are used in determining our estimated reserve quantities. The technical persons responsible for preparing the reserves estimates presented herein meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Society of Petroleum Engineers' Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information. ECA's internal control over its reserve reporting process is designed to result in accurate and reliable estimates in compliance with applicable regulations and guidance. Internal reserve preparation is performed by staff reservoir engineers and geoscientists before review by the Reservoir Engineering Manager and finally the Chief Operating Officer. These individuals consult regularly with Ryder Scott during the reserve estimation process to review properties, assumptions, and any new data available. Additionally, ECA's senior management reviewed and approved all Ryder Scott reserve reports contained herein.

ECA's reserves are estimated by the Reservoir Engineering Manager. The Reservoir Engineering Manager has a Bachelor of Science degree in Petroleum Engineering. He has over six years of oil and gas industry experience in Reservoir Engineering. During that time, he has focused on reserves estimates and project economics.

ECA's Chief Operating Officer is the primary technical person responsible for overseeing the reserve reporting process. This individual has a Bachelor of Science degree in Chemical Engineering with Masters of Petroleum Engineering coursework along with a Master of Business Administration degree. He has worked in drilling, completions, production, and reservoir engineering along with acquisitions during his career and is a member of the Society of Petroleum Engineers. He has over ten years of experience in reserve evaluation.

Sale and Abandonment of Underlying Properties

ECA and any transferee will have the right to abandon its interest in any well or property comprising a portion of the Underlying Properties if, in its opinion, such well or property ceases to produce or is not capable of producing in commercially paying quantities. To reduce or eliminate the potential conflict of interest between ECA and the Trust in determining whether a well is capable of producing in commercially paying quantities, ECA is required under the applicable conveyance to act as a reasonably prudent operator in the AMI under the same or similar circumstances would act if it were acting with respect to its own properties, disregarding the existence of the royalty interests as a burden affecting such property.

ECA generally may sell all or a portion of its interests in the Underlying Properties, subject to and burdened by the Royalty Interests, without the consent of the Trust unitholders. In addition, ECA may, without the consent of the Trust unitholders, require the Trust to release Royalty Interests with an aggregate value to the Trust not to exceed $5.0 million during any 12-month period. These releases will be made only in connection with a sale by ECA of the Underlying Properties and are conditioned upon the Trust receiving an amount equal to the fair value to the Trust of such Royalty Interests. ECA operates all of the wells subject to the Royalty Interests. ECA continues to be the operator of all of the wells subject to the Royalty Interests although, as of January 1, 2013, it is no longer contractually obligated to the Trust to remain so. Any net sales proceeds paid to the Trust are distributable to Trust unitholders for the quarter in which they are received. ECA has not identified for sale any of the Underlying Properties.

Title to Properties

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

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

ECA's interests in the gas properties comprising the Underlying Properties are typically subject, in one degree or another, to one or more of the following:

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

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

ECA believes that its title to the Underlying Properties, and the Trust's title to the Royalty Interests, is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions as are not so material as to detract substantially from the use or value of such properties or Royalty Interests. Prior to drilling a PUD Well, ECA obtained a preliminary title review to ensure there were no obvious defects in title to the well. The conveyance related to the PUD Royalty Interest obligated ECA to conduct a more thorough title examination of the drill site tract prior to drilling any of the PUD Wells.

It is unclear under Pennsylvania law whether the Royalty Interests would be treated as real property interests. Nevertheless, ECA has recorded the conveyances of the Royalty Interests in the real property records of Pennsylvania in accordance with local recording acts. ECA also has granted to the Trust the Royalty Interest Lien to provide protection to the Trust, in the event of a bankruptcy of ECA, against the risk that the Royalty Interests were not considered real property interests.

Description of the Royalty Interests

The Royalty Interests were conveyed to the Trust by ECA by means of conveyance instruments that have been recorded in the appropriate real property records in Greene County, Pennsylvania where the gas properties to which the Underlying Properties relate are located. The PDP Royalty Interest burdens the existing working interests owned by ECA in the Producing Wells. ECA has an average working interest of approximately 93% in these wells.

The PUD Royalty Interest initially burdened 50% of all of the interests of ECA in the Marcellus Shale formation in the AMI. ECA's interests in the gas properties to which the PUD Wells relate consist of an average working interest of 100%. The conveyance related to the PUD Royalty Interest, however, provided that the proceeds from the PUD Wells would be calculated on the basis that the PUD Wells were only burdened by interests that in total would not exceed 12.5%. In the event that ECA's interest in any of the wells subject to the PUD Royalty Interest that are drilled is subject to burdens in excess of 12.5%, such burdens will be fully allocated against ECA's retained interest in such well, the net effect of which is that the Trust will receive payments with respect to the PUD Royalty Interest as if the burdens affecting the PUD Wells were in total 12.5% (proportionately reduced).

Generally, the percentage of production proceeds received by the Trust with respect to a well equals the product of (i) the percentage of proceeds to which the Trust is entitled under the terms of the conveyances (90% for the Producing Wells and 50% for the PUD Wells) multiplied by (ii) ECA's net revenue interest in the well. ECA on average owns an 81.53% net revenue interest in the Producing Wells. Therefore, the Trust is entitled to receive on average 73.37% of the proceeds of production from the Producing Wells. With respect to the PUD Wells, the conveyance related to the PUD Royalty Interest provides that the proceeds from the PUD Wells will be calculated on the basis that the underlying PUD Wells are burdened only by interests that in total would not exceed 12.5% of the revenues from such properties, regardless of whether the royalty interest owners are actually entitled to a greater percentage of revenues from such properties. As an example, assuming ECA owns a 100% working interest in a PUD Well, the applicable net revenue interest is calculated by multiplying ECA's percentage working interest in the 100% working interest well by the unburdened interest percentage (87.5%), and such well would have a minimum 87.5% net revenue interest. Accordingly, the Trust is entitled to a minimum of 43.75% of the production proceeds from the well provided in this example. To the extent ECA's working interest in a PUD Well is less than 100%, the Trust's share of proceeds would be proportionately reduced.

PDP Royalty Interest. The conveyances creating the PDP Royalty Interest entitle the Trust to receive an amount of cash for each calendar quarter equal to 90% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of estimated natural gas production attributable to the Producing Wells regardless of whether such amounts have actually been received by ECA from the purchases of the natural gas produced. Proceeds from the sale of natural gas production attributable to the Producing Wells in any calendar quarter means:

- the amount calculated based on estimated production volumes attributable to the Producing Wells;

in each case, after deducting the Trust's proportionate share of:

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

- post-production costs, which generally consist of costs incurred to gather, compress, transport, process, treat, dehydrate and market the natural gas produced. Charges payable to ECA for such post-production costs on the Greene County Gathering System were limited to $0.52 per

MMBtu of gas gathered until ECA fulfilled its drilling obligation, after which ECA may increase the Post-Production Service Fee to the extent it is necessary to recover certain capital expenditures in the Greene County Gathering System. Additionally, the Trust is charged for the cost of fuel used in the compression process, including equivalent electricity charges in instances when electric compressors are used.

Proceeds payable to the Trust from the sale of natural gas production attributable to the Producing Wells in any calendar quarter are not subject to any deductions for any expenses attributable to exploration, drilling, development, operating, maintenance or any other costs incident to the production of natural gas production attributable to the Producing Wells, including any costs to plug and abandon a Producing Well.

PUD Royalty Interest. The conveyance creating the PUD Royalty Interest entitles the Trust to receive an amount of cash for each calendar quarter equal to 50% of the proceeds (after deducting post-production costs and any applicable taxes) from the sale of estimated natural gas production attributable to the PUD Wells regardless of whether such amounts have actually been received by ECA from the purchase of the natural gas produced. Proceeds from the sale of natural gas production, if any, attributable to the PUD Wells in any calendar quarter means:

- for any calendar quarter commencing on or after April 1, 2010, the amount calculated based on estimated production volumes attributable to the PUD Wells:

in each case after deducting the Trust's proportionate share of:

- any taxes levied on the severance or production of the natural gas produced from the PUD Wells and any property taxes attributable to the gas produced from the PUD Wells; and
- post-production costs, which generally consist of costs incurred to gather, compress, transport, process, treat, dehydrate and market the natural gas produced. Charges payable to ECA for such post-production charges on the Greene County Gathering System were limited to $0.52 per MMBtu of gas gathered until ECA has fulfilled its drilling obligation, after which ECA may increase the Post-Production Services Fee to the extent necessary to recover certain capital expenditures in the Greene County Gathering System. Additionally, the Trust is charged for the cost of fuel used in the compression process, including equivalent electricity charges in instances when electric compressors are used.

Proceeds, if any, payable to the Trust from the sale of natural gas production attributable to the PUD Wells in any calendar quarter:

- are determined on the basis that ECA's working interest with respect to the PUD Wells is not subject to burdens (landowner's royalties and other similar interests) in excess of 12.5% of the proceeds from gas production attributable to ECA's interest; and
- are be subject to any deductions for any expenses attributable to exploration, drilling, development, operating, maintenance or any other costs incident to the production of natural gas production attributable to the underlying PUD properties, including any costs to plug and abandon a well included in the underlying PUD properties.

Royalty Interest Lien

Under the laws of Pennsylvania, it is not clear that the Royalty Interests conveyed by ECA to the Trust would be treated as real property interests. Therefore, ECA has granted to the Trust a lien (the "Royalty Interest Lien") to provide protection to the Trust, exercisable in the event of a bankruptcy of ECA, against the risk that the Royalty Interests were not considered real property interests. More specifically, the Royalty Interest Lien is a lien in the Subject Interest and the Subject Gas, to the extent and only to the extent that such Subject Interest and Subject Gas pertains to Gas in, under and that may be produced, saved or sold from the Marcellus Shale formation from the wellbore of the Producing Wells and the PUD Wells, sufficient to cause the Trust to receive a volume of Trust Gas calculated in accordance with the provisions of the conveyances of the Royalty Interests.

The Royalty Interest Lien does not include ECA's retained interest in the PUD and Producing Wells and the AMI or other interest of ECA in the AMI, and ECA has the right to lien, mortgage, sell or otherwise encumber the ECA retained interest subject to the Royalty Interest Lien.

ECA has recorded the conveyances of the Royalty Interests and a Mortgage/Fixture Filing in the real estate records of Greene County, Pennsylvania and has filed a corresponding UCC-1 Financing Statement in the Office of the Secretary of State of West Virginia and the Commonwealth of Pennsylvania.

The conveyances also provide that if ECA's interest with respect to the PDP properties is greater than what was warranted to the Trust in the conveyances, ECA will have the right to offset against amounts owed to the Trust, the difference between what the Trust actually receives from PDP Royalty Interest and what the Trust should have received from the PDP Royalty Interest had ECA's interest been the amount warranted.

Additional Provisions

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

- amounts withheld or placed in escrow by a purchaser are not considered to be received by the owner of the underlying property until actually collected;
- amounts received by the owner of the underlying property and promptly deposited with a nonaffiliated escrow agent will not be considered to have been received until disbursed to it by the escrow agent; and
- amounts received by the owner of the underlying property and not deposited with an escrow agent will be considered to have been received.

The Trustee is not obligated to return any cash received from the Royalty Interests. However, any overpayments made to the Trust by ECA due to adjustments to prior calculations of proceeds or otherwise will reduce future amounts payable to the Trust until ECA recovers the overpayments.

The conveyances generally permit ECA to sell, without the consent or approval of the Trust unitholders, all or any part of its interest in the Underlying Properties, if the Underlying Properties are sold, subject to and burdened by the Royalty Interests. The Trust unitholders are not entitled to any proceeds of any sale of ECA's interest in the Underlying Properties that remains subject to and burdened by the Royalty Interests. Following any such sale, the proceeds attributable to the transferred property will be calculated pursuant to the conveyances as described in this report, and paid by the purchaser or transferee to the Trust.

ECA or any transferee of an Underlying Property will have the right to abandon any well or property if it reasonably believes the well or property ceases to produce or is not capable of producing in commercially paying quantities. In making such decisions, ECA or any transferee of an Underlying Property is required under the applicable conveyance to act as a reasonably prudent operator in the AMI under the same or similar circumstances would act if it were acting with respect to its own properties, disregarding the existence of the Royalty Interests as burdens affecting such property. Upon termination of the lease, that portion of the Royalty Interests relating to the abandoned property will be extinguished.

ECA may, without the consent of the Trust unitholders, require the Trust to release Royalty Interests with an aggregate value to the Trust up to $5.0 million during any twelve month period. These releases will be made only in connection with a sale by ECA of the Underlying Properties and are conditioned upon the Trust receiving an amount equal to the fair value to the Trust of such Royalty Interests.

ECA must maintain books and records sufficient to determine the amounts payable for the Royalty Interests to the Trust. Quarterly and annually, ECA must deliver to the Trustee a statement of the computation of the proceeds for each computation period as well as quarterly drilling and production results.

Item 3. *Legal Proceedings.*

None.

Item 4. *Mine Safety Disclosures*

Not applicable.

PART II

Item 5. *Market for Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities.*

The Trust units commenced trading on the New York Stock Exchange on July 1, 2010 under the symbol "ECT." The high and low closing sales prices per unit for each quarter in 2012 and 2013 were as follows:

Quarter	High	Low
2012		
First Quarter (January 1 through March 31)	$ 26.69	$ 19.62
Second Quarter (April 1 through June 30)	$ 21.39	$ 16.12
Third Quarter (July 1 through September 30)	$ 22.11	$ 18.53
Fourth Quarter (October 1 through December 31)	$ 21.45	$ 15.27
2013		
First Quarter (January 1 through March 31)	$ 18.95	$ 10.30
Second Quarter (April 1 through June 30)	$ 13.70	$ 9.19
Third Quarter (July 1 through September 30)	$ 10.66	$ 9.20
Fourth Quarter (October 1 through December 31)	$ 10.37	$ 7.00

At December 31, 2013, the 17,605,000 units outstanding were held by 49 unitholders of record.

Distributions

Each quarter, the Trustee determines the amount of funds available for distribution to the Trust unitholders, as described elsewhere in this report. Quarterly cash distributions during the term of the Trust are made by the Trustee generally no later than 60 days following the end of each quarter (or the next succeeding business day) to the Trust unitholders of record on the 45th day following the end of each quarter (or the next succeeding business day). The table below presents the net cash proceeds for each quarter of 2012 and 2013, the Trust expenses, and the resulting distributable income per Trust unit (dollars in thousands, except distributable income per unit).

	31-Mar	30-Jun	30-Sep	31-Dec	Total
2012					
Net proceeds	$ 9,224	$ 8,750	$ 9,157	$ 9,265	$ 36,396
General and administrative	$ 533	$ 416	$ 80	$ 256	$ 1,285
Distributable income	$ 9,191	$ 8,335	$ 9,077	$ 9,009	$ 35,612
Distributable income per common unit	$ 0.574	$ 0.602	$ 0.624	$ 0.682	$ 2.482
Distributable income per subordinated unit	$ 0.366	$ 0.088	$ 0.190	$ 0.000	$ 0.644
2013					
Net proceeds	$ 8,243	$ 8,661	$ 7,045	$ 6,573	$ 30,522
General and administrative	$ 441	$ 264	$ 164	$ 201	$ 1,070
Distributable income	$ 7,802	$ 8,397	$ 6,881	$ 6,372	$ 29,452
Distributable income per common unit	$ 0.443	$ 0.477	$ 0.391	$ 0.362	$ 1.673

Subsequent to year end, on or before February 28, 2014, a distribution of $0.362 per unit was paid to Trust common unitholders owning Trust common units as of February 19, 2014.

The Subordination Period terminated on December 31, 2012. Consequently, the fourth quarter of 2012 was the last quarter during which common unitholders had the protection of the subordination provisions. At December 31, 2012, the 4,401,750 subordinated units converted to common units. As common units, such 4,401,750 units are entitled to the same distributions as all other common units, and no common units will be entitled to any benefit formerly conferred upon them by the subordination provisions.

Equity Compensation Plans

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

Recent Sales of Unregistered Securities

None.

Purchases of Equity Securities

There were no purchases of Trust units by the Trust or any affiliated purchaser during the fourth quarter of 2013.

Item 6. ***Selected Financial Data.***

The following is a summary of net proceeds, distributable income, and distributable income per unit by quarter in 2010, 2011, 2012 and 2013 (all amounts in thousands except distributable income per unit):

	31-Mar	30-Jun	30-Sep	31-Dec	Total
2010					
Net proceeds	N/A	$ 5,566	$ 7,918	$ 9,188	$ 22,672
Distributable income	N/A	$ 4,789	$ 7,419	$ 8,809	$ 21,017
Distributable income per common unit	N/A	$ 0.272	$ 0.421	$ 0.500	$ 1.193
Distributable income per subordinated unit	N/A	$ 0.272	$ 0.421	$ 0.500	$ 1.193
2011					
Net proceeds	$ 9,834	$ 11,715	$ 11,427	$ 10,556	$ 43,532
Distributable income	$ 9,232	$ 11,114	$ 11,083	$ 10,465	$ 41,894
Distributable income per common unit	$ 0.524	$ 0.631	$ 0.630	$ 0.594	$ 2.379
Distributable income per subordinated unit	$ 0.524	$ 0.631	$ 0.630	$ 0.594	$ 2.379
2012					
Net proceeds	$ 9,224	$ 8,750	$ 9,157	$ 9,265	$ 36,396
Distributable income	$ 9,191	$ 8,335	$ 9,077	$ 9,009	$ 35,612
Distributable income per common unit	$ 0.574	$ 0.602	$ 0.624	$ 0.682	$ 2.482
Distributable income per subordinated unit	$ 0.366	$ 0.088	$ 0.190	$ 0.000	$ 0.644
2013					
Net proceeds	$ 8,243	$ 8,661	$ 7,045	$ 6,573	$ 30,522
Distributable income	$ 7,802	$ 8,397	$ 6,881	$ 6,372	$ 29,452
Distributable income per common unit	$ 0.443	$ 0.477	$ 0.391	$ 0.362	$ 1.673

Item 7. ***Trustee's Discussion and Analysis of Financial Condition and Results of Operation.***

This document contains forward-looking statements, which describe current expectations or forecasts of future events. Please refer to "Forward-Looking Statements" which follows the Table of Contents of this Form 10-K for an explanation of these types of statements and their limitations.

Results of Trust Operations

For the Twelve months ended December 31, 2013 compared to Twelve months ended December 31, 2012

Distributable income for the year ended December 31, 2013 decreased to $29.5 million from $35.6 million for the year ended December 31, 2012. Compared to the year ended December 31, 2012, royalty income increased $0.3 million, hedge proceeds decreased $6.2 million, and general and administrative expenses decreased $0.2 million. During the year ended December 31, 2012 the Trustee released $0.5 million of cash reserves; no reserves were withheld or released during the year ended December 31, 2013.

Royalty income increased from $23.2 million for the year ended December 31, 2012 to $23.5 million for the year ended December 31, 2013, an increase of $0.3 million. This increase was due to an increase in the average realized price and a decrease in post production costs, partially offset by a decrease in production.

The average price realized for the year ended December 31, 2013 increased $0.57 per Mcf to $3.90 per Mcf as compared to $3.33 for the year ended December 31, 2012. This increase was the result of an increase in the average sales price for gas production, and a decrease in post production costs, partially offset by a decrease in the average hedged price. The average sales price, before the effects of hedges and post production costs, increased from $2.87 per Mcf for the year ended December 31, 2012 to $3.71 per Mcf for the year ended December 31, 2013. This increase in price was primarily the result of an increase in the weighted average monthly closing NYMEX price for the current period to $3.65 per MMBtu compared to the year ended December 31, 2012 weighted average monthly closing NYMEX price of $2.78 per MMBtu, partially offset by a $0.03 decrease in the average Basis compared to the prior period.

Post production costs consist of a post-production services fee together with a charge for electricity used in lieu of gas for compression on the gathering system and firm transportation charges on interstate gas pipelines and, as of July 2013, an additional gathering charge for system enhancements applicable to certain wells in an effort to increase production by reducing the high line pressure previously experienced by those wells. Overall, average post production costs decreased to $0.71 per Mcf for the year ended December 31, 2013 as compared to $0.75 per Mcf for the year ended December 31, 2012. Post production costs were lower than the previous year primarily as a result of a reduction in the firm transportation rate charged by Columbia Gas Transmission, LLC ("TCO"). Effective March 1, 2013, TCO's filed tariff rate was reduced from $0.1996 per MMBtu to $0.1878 per MMBtu at a one hundred percent load factor. Also, a one-time cash refund of approximately $0.3 million from TCO representing retroactive application of the reduced rate covering the period from January 2012 through February 2013 was received in June 2013. These decreases were partially offset by an increase of $0.01 per Mcf in the charges for electricity (used in lieu of gas) for compression.

Production decreased 28% from 10,931 MMcf for the year ended December 31, 2012 to 7,835 MMcf for the year ended December 31, 2013. The decreased production was primarily a result of natural production declines that occur during the early life of a well, partially offset by the result of nine wells that were turned online during the year ended December 31, 2012 being online for all of the year ended December 31, 2013.

Hedged volumes for the year ended December 31, 2013 totaled 5,241,000 MMBtu covered by a $5.00 per MMBtu floor price contract. For the year ended December 31, 2012, hedged volumes totaled 4,917,000 MMBtu consisting of 1,365,000 MMBtu covered by a fixed price swap at a price of $6.82 per MMBtu and 3,552 ,000 MMBtu covered by a $5.00 per MMBtu floor price contract resulting in an average hedge price of approximately $5.51 per MMBtu for the hedged volume. The average hedge price per MMBtu declined from $5.51 per MMBtu for the year ended December 31, 2012 to $5.00 per

MMBtu for the year ended December 31, 2013 due to the expiration of the swap contracts. Although there was an increase in volumes covered by hedge contracts, proceeds received by the Trust for the year ended December 31, 2013 of $7.1 million, as compared to the $13.2 million for the year ended December 31, 2012, decreased as a result of the decrease in the average hedge price and the increase in the average NYMEX price as discussed previously.

The fixed price swap contracts terminated June 30, 2012. The floor hedging arrangements terminate March 31, 2014. Distributions after the hedging arrangements terminate may be substantially more volatile, and could, depending on natural gas prices, be substantially lower or higher than those during the period that the hedging arrangements were in effect.

General and administrative expenses paid by the Trust were $1.1 million for the year ended December 31, 2013 as compared to $1.3 million for the year ended December 31, 2012. The decrease in expenses was primarily related to a decrease of $0.1 million in professional fees for tax services and a decrease of $0.1 million in legal costs during the year ended December 31, 2013.

Prior to 2012, the Trustee had established a net cash reserve of $500,000 for use in paying current and future liabilities of the Trust as they become due. The Trustee released the cash reserve during the year ended December 31, 2012, but may re-establish a reserve of any amount at any time. The release of the cash reserve increased distributable income for the year ended December 31, 2012.

For the Twelve months ended December 31, 2012 compared to the Twelve months ended December 31, 2011

Distributable income for the year ended December 31, 2012 decreased to $35.6 million from $41.9 million for the year ended December 31, 2011. Compared to the year ended December 31, 2011, royalty income decreased $11.7 million, hedge proceeds increased $4.6 million, and general and administrative expenses decreased $0.4 million. During the year ended December 31, 2012, the Trustee released a cash reserve of $0.5 million that it had established during the period ended December 31, 2010.

Royalty income decreased from $34.8 million for the year ended December 31, 2011 to $23.2 million for the year ended December 31, 2012, a decrease of $11.7 million. This decrease was due to a decrease in the average realized price and an increase in post production costs, partially offset by an increase in production.

The average price realized for the year ended December 31, 2012 declined $1.11 per Mcf to $3.33 per Mcf as compared to $4.44 per Mcf for the year ended December 31, 2011. This decrease was the result of a decrease in the average sales price for gas production, an increase in post production costs, and a decrease in the average hedged price. The average sales price, before the effects of hedges and post production costs, declined from $4.26 per Mcf for the year ended December 31, 2011 to $2.87 per Mcf for the year ended December 31, 2012. This decrease in price was primarily the result of a decline in the weighted average monthly closing NYMEX price for the year ended December 31, 2012 to $2.78 per MMBtu compared to the period ended December 31, 2011 weighted average monthly closing NYMEX price of $4.02 per MMBtu.

Post production costs consist of a post-production services fee together with a charge for electricity used in lieu of gas for compression on the gathering system and firm transportation charges on interstate gas pipelines, averaged $0.75 per Mcf for the year ended December 31, 2012 as compared to an average of $0.71 per Mcf for the year ended December 31, 2011. Post production costs were higher than the previous period as a result of firm transportation charges on the TCO interstate pipeline system beginning in August 2011, resulting in an average $0.08 per Mcf increase in costs from the year ended December 31, 2011. This was partially offset by an average $0.04 per Mcf decline in the charge for electricity usage from the year ended December 31, 2011 to the year ended December 31, 2012.

Production increased 11% from 9,813 MMcf for the year ended December 31, 2011 to 10,931 MMcf for the year ended December 31, 2012. The increased production was primarily the result of an increase in the number of wells online and producing during the year ended December 31, 2012, partially offset by natural production declines. A total of fifty-four wells (14 PDP and 40 PUD Wells (52.06 Equivalent PUD Wells)) were online and producing as of December 31, 2012, while there were a total of forty-five wells (14 PDP and 31 PUD Wells (39.84 Equivalent PUD Wells)) online and producing as of December 31, 2011. The Trust experienced production curtailments during the year ended December 31, 2012 as a result of facility delays while waiting for government permits, which were approved during the second quarter of 2012. The additional gathering systems and/or transportation pipelines were constructed and became operational in late June 2012, allowing increased volumes.

Hedged volumes for the year ended December 31, 2012 totaled 4,917,000 MMBtu consisting of 1,365,000 MMBtu covered by a fixed price swap at a price of $6.82 per MMBtu and 3,552,000 MMBtu covered by a $5.00 per MMBtu floor price contract resulting in an average hedge price of approximately $5.51 per MMBtu for the hedged volume. For the year ended December 31, 2011, hedged volumes totaled 3,895,500 MMBtu consisting of 1,357,500 MMBtu covered by a fixed price swap at a price of $6.75 per MMBtu, 1,380,000 MMBtu covered by a fixed price swap at a price of $6.82 per MMBtu and 1,158,000 MMBtu covered by $5.00 per MMBtu floor price contracts resulting in an average hedge price of approximately $6.28 per MMBtu for the hedged volume. The average hedge price per MMBtu declined from $6.28 per MMBtu for the year ended December 31, 2011 to $5.51 per MMBtu for the year ended December 31, 2012 due to the expiration of the swap contracts and a larger floor position. Although there was a decrease in the average hedge price, proceeds received by the Trust for the year ended December 31, 2012 increased as a result of the decrease in the average NYMEX price as discussed previously and an increase in the volumes covered by the floor contracts.

General and administrative expenses paid by the Trust were $1.3 million for the year ended December 31, 2012 as compared to $1.6 million for the year ended December 31, 2011. The decrease in expenses was primarily related to a decrease of $0.6 million in state franchise taxes paid, partially offset by a $0.3 million increase in professional fees for tax services during the year ended December 31, 2012.

During the period ended December 31, 2010, the Trustee established a net cash reserve of $500,000 for use in paying current and future liabilities of the Trust as they become due. The Trustee released the cash reserve during the year ended December 31, 2012, but may re-establish a reserve of any amount at any time. The release of the cash reserve increased distributable income for the year ended December 31, 2012.

Overview

The Trust is a statutory trust created under the Delaware Statutory Trust Act. The Bank of New York Mellon Trust Company, N.A. serves as Trustee. The Trust does not conduct any operations or activities. The Trust's purpose is, in general, to hold the Royalty Interests, to distribute to the Trust unitholders cash that the Trust receives in respect of the Royalty Interests after payment of Trust expenses, and to perform certain administrative functions in respect of the Royalty Interests and the Trust units. The Trustee has no authority or responsibility for, and no involvement with, any aspect of the oil and gas operations on the properties to which the Royalty Interests relate. The Trust derives all or substantially all of its income and cash flows from the Royalty Interests, which in turn are subject to the hedge contracts, described in Part I, Item 1. The Trust is treated as a partnership for federal and state income tax purposes.

ECA completed its drilling obligation to the Trust under the Development Agreement as of November 30, 2011. This completion date was approximately 2.3 years in advance of the required completion date of March 31, 2014. Consequently, no additional wells will be drilled for the Trust, and the subordinated units automatically converted on a one-for-one basis into ECT Common Units on December 31, 2012. The last cash distribution supported by the ECT Subordinated Units was the cash distribution payable with respect to the proceeds for the fourth quarter of 2012, which was paid on February 28, 2013. Beginning with the cash distribution payable with respect to the first quarter of 2013, all ECT trust units share in all cash distributions on a pro rata basis. As of December 31, 2013 the Trust owns Royalty Interests in the 14 Producing Wells and the 40 development wells (52.06 Equivalent PUD Wells calculated in accordance with the Development Agreement and as described in the Prospectus) that are now completed and in production.

The Royalty Interests were conveyed from ECA's working interest in the Producing Wells and the PUD Wells limited to the Underlying Properties. The PDP Royalty Interest entitles the Trust to receive 90% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of production of natural gas attributable to ECA's interest in the Producing Wells for a period of 20 years commencing on April 1, 2010 and 45% thereafter. The PUD Royalty Interest entitles the Trust to receive 50% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of production of natural gas attributable to ECA's interest in the PUD Wells for a period of 20 years commencing on April 1, 2010 and 25% thereafter. Approximately 50% of the originally estimated natural gas production attributable to the Royalty Interests has been hedged through March 31, 2014.

ECA was obligated to drill all of the PUD Wells by March 31, 2014. As of November 30, 2011, ECA had fulfilled its drilling obligation to the Trust by drilling 40 PUD Wells (52.06 Equivalent PUD Wells), calculated as provided in the Development Agreement. The Trust was not responsible for any costs related to the drilling of development wells or any other development or operating costs. The Trust's cash receipts in respect of the Royalty Interests are determined after deducting post-production costs and any applicable taxes associated with the Royalty Interests, and the Trust's cash available for distribution includes any cash receipts from the hedge contracts and is reduced by Trust administrative expenses. Post-production costs generally consist of costs incurred to gather, compress, transport, process, treat, dehydrate and market the natural gas produced. Charges payable to ECA for such post-production costs on its Greene County Gathering System were limited to $0.52 per MMBtu gathered until ECA fulfilled its drilling obligation; thereafter, ECA may increase the Post-Production Services Fee to the extent necessary to recover certain capital expenditures in the Greene County Gathering System.

Generally, the percentage of production proceeds to be received by the Trust with respect to a well equals the product of (i) the percentage of proceeds to which the Trust is entitled under the terms of the conveyances (90% for the Producing Wells and 50% for the PUD Wells) multiplied by (ii) ECA's net revenue interest in the well. ECA on average owns an 81.53% net revenue interest in the Producing Wells. Therefore, the Trust is entitled to receive on average 73.37% of the proceeds of production from the Producing Wells. With respect to the PUD Wells, the conveyance related to the PUD Royalty Interest provides that the proceeds from the PUD Wells will be calculated on the basis that the underlying PUD Wells are burdened only by interests that in total would not exceed 12.5% of the revenues from such properties, regardless of whether the royalty interest owners are actually entitled to a greater percentage of revenues from such properties. As an example, assuming ECA owns a 100% working interest in a PUD Well, the applicable net revenue interest is calculated by multiplying ECA's percentage working interest in the 100% working interest well by the unburdened interest percentage (87.5%), and such well would have a minimum 87.5% net revenue interest. Accordingly, the Trust is entitled to a minimum of 43.75% of the production proceeds from the well provided in this example. To the extent ECA's working interest in a PUD Well is less than 100%, the Trust's share of proceeds would be proportionately reduced.

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting Trust administrative expenses and costs and reserves therefor, on or about 60 days following the completion of each quarter. The first quarterly distribution was made on August 31, 2010 to record unitholders as of August 16, 2010. The Trust will terminate in March 2030.

The amount of Trust revenues and cash distributions to Trust unitholders will depend on, among other things:

- natural gas prices received;
- the volume and Btu rating of natural gas produced and sold;
- post-production costs and any applicable taxes;
- administrative expenses of the Trust including expenses incurred as a result of being a publicly traded entity, and any changes in amounts reserved for such expenses; and
- the effects of the hedging arrangements, and the expiration of the hedging arrangements.

The amount of the quarterly distributions will fluctuate from quarter to quarter, depending on the proceeds received by the Trust, among other factors. There is no minimum required distribution. In order to provide support for cash distributions on the common units for a limited period of time, ECA agreed to subordinate 4,401,250 of the Trust units it originally acquired, which constituted 25% of the outstanding Trust units. 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 which was at least equal to the applicable quarterly subordination threshold. However, if there was not sufficient cash to fund such a distribution on all Trust units, the distribution with respect to the subordinated units was 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 these Trust units, and in order to provide additional financial incentive to ECA to perform its drilling obligation and operations on the Underlying Properties in an efficient and cost-effective manner, ECA 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 exceeded 150% of the subordination threshold for such quarter. ECA's right to receive the incentive distributions, and the benefits of the subordination provision to the holders of common units, terminated upon the expiration of the Subordination Period.

The subordinated units automatically converted into common units on a one-for-one basis and ECA's right to receive incentive distributions terminated on December 31, 2012. Because the Subordination Period terminated on December 31, 2012, the fourth quarter of 2012 was the last quarter that the common unitholders were eligible to receive a distribution in the amount of the Subordination Threshold. The table below sets forth the Target Distributions and Subordination and Incentive Thresholds for each quarter through the fourth quarter of 2012.

The effective date of the Trust was April 1, 2010, meaning the Trust has received the proceeds of production attributable to the PDP Royalty Interest from that date even though the PDP Royalty Interest was not conveyed to the Trust until July 7, 2010.

	Subordination Threshold	Target Distribution	Incentive Threshold
2010:			
Second Quarter	$ 0.181	$ 0.227	$ 0.272
Third Quarter	0.334	0.417	0.501
Fourth Quarter	0.478	0.597	0.716
2011:			
First Quarter	0.446	0.558	0.669
Second Quarter	0.451	0.564	0.676
Third Quarter	0.550	0.688	0.825
Fourth Quarter	0.565	0.706	0.847
2012:			
First Quarter	0.574	0.717	0.861
Second Quarter	0.602	0.752	0.903
Third Quarter	0.624	0.780	0.937
Fourth Quarter	0.701	0.876	1.051

Pursuant to IRC Section 1446, withholding tax on income effectively connected to a United States trade or business allocated to foreign partners should be made at the highest marginal rate. Under Section 1441, withholding tax on fixed, determinable, annual, periodic income from United States sources allocated to foreign partners should be made at 30% of gross income unless the rate is reduced by treaty. This release is intended to be a qualified notice to nominees and brokers as provided for under Treasury Regulation Section 1.1446-4(b) by ECA Marcellus Trust I, and while specific relief is not specified for Section 1441 income, this disclosure is intended to suffice. Nominees and brokers should withhold 39.6% of the distribution made to foreign partners.

Liquidity and Capital Resources

The Trust has no source of liquidity or capital resources other than cash flows from the Royalty Interests and hedge proceeds, if any. Other than Trust administrative expenses, including, if applicable, expense reimbursements to ECA and any reserves established by the Trustee for future liabilities, the Trust's only use of cash is for distributions to Trust unitholders. Administrative expenses include payments to the Trustee and the Delaware Trustee as well as a quarterly fee of $15,000 to ECA pursuant to the 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 Royalty Interests and other sources (such as interest earned on any amounts reserved by the Trustee) that quarter, over the Trust's expenses for that quarter. Available funds are reduced by any cash the Trustee determines to hold as a reserve against future expenses or liabilities. The Trustee may borrow funds required to pay expenses or liabilities if the Trustee determines that the cash on hand and the cash to be received are insufficient to cover the Trust's expenses or liabilities. If the Trustee borrows funds, the Trust unitholders will not receive distributions until the borrowed funds are repaid.

Payments to the Trust in respect of the Royalty Interests are based on the complex provisions of the various conveyances held by the Trust, copies of which are filed as exhibits to this report, and reference is hereby made to the text of the conveyances for the actual calculations of amounts due to the Trust.

The Trust does not have any transactions, arrangements or other relationships with unconsolidated entities or persons that could materially affect the Trust's liquidity or the availability of capital resources.

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 commodity hedge contracts disclosed in the section "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Annual Report on Form 10-K.

Contractual Obligations

A summary of the Trust's contractual obligations as of December 31, 2013 is provided in the following table (in thousands):

	Payments Due by Year						
	2014	2015	2016	2017	2018	Thereafter	Total
Administrative services fee	$ 60.0	$ 60.0	$ 60.0	$ 60.0	$ 60.0	$ 600.0	$ 900.0
Trustee administrative fee	150.0	150.0	150.0	150.0	150.0	1,500.0	2,250.0
Delaware trustee fee	2.5	2.5	2.5	2.5	2.5	25.0	37.5
	$ 212.5	$ 212.5	$ 212.5	$ 212.5	$ 212.5	$ 2,125.0	$ 3,187.5

Pursuant to the terms of the Administrative Services Agreement with ECA, the Trust is obligated to pay ECA an annual administrative services fee of $60,000 for accounting, bookkeeping and informational services relating to the Royalty Interests to be performed by ECA on behalf of the Trust throughout the term of the Trust. Pursuant to the Trust Agreement, the Trustee is to be paid an administrative fee of $150,000 per year until January 1, 2016, after which date the fee will be adjusted annually, up or down, by the amount of the change in the All Urban Consumers (CPI-U)—US City Average for the immediately preceding calendar year, not to exceed +/- 3% in any one year. The Trust is also obligated to pay the Delaware Trustee a fee of $2,500 per year, throughout the term of the Trust.

ECA and the Trustee each may terminate the provisions of the Administrative Services Agreement relating to the provision by ECA of administrative services at any time following delivery of notice no less than 90 days prior to the date of termination; provided, however, that ECA may not terminate the Administrative Services Agreement except in connection with ECA's transfer of some or all of the Subject Interests, as defined in the Conveyances, and then only with respect to the Services to be provided with respect to the Subject Interests being transferred, and only upon the delivery to the Trustee of an agreement of the transferee of such Subject Interests reasonably satisfactory to the Trustee in which such transferee assumes the responsibility to perform the Services relating to the Subject Interests being transferred.

New Accounting Pronouncements

None applicable.

Significant Accounting Policies

The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP") because certain cash reserves may be established for contingencies, which would not be accrued in financial statements prepared in accordance with GAAP. Amortization of the investment in overriding royalty interests calculated on a unit-of-production basis is charged directly to Trust Corpus. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission as specified by FASB ASC Topic 932 Extractive Activities—Oil and Gas: Financial Statements of Royalty Trusts.

Income determined on the basis of GAAP would include all expenses incurred for the period presented. However, the Trust serves as a pass-through entity, with expenses for depreciation, depletion, and amortization, interest and income taxes being based on the status and elections of the Trust unitholders. General and administrative expenses, production taxes or any other allowable costs are charged to the Trust only when cash has been paid for those expenses. In addition, the Royalty Interests are not burdened by field and lease operating expenses. Thus, the statement shows distributable income, defined as income of the Trust available for distribution to the Trust unitholders before application of those additional unitholders' additional expenses, if any, for depreciation, depletion, and amortization, interest and income taxes. The revenues are reflected net of existing royalties and overriding royalties and have been reduced by gathering/post-production expenses.

Revenue and Expenses:

The Trust serves as a pass-through entity, with items of depletion, interest income and expense, and income tax attributes being based upon the status and election of the unitholders. Thus, the Statements of Distributable Income show Income available for distribution before application of those unitholders' additional expenses, if any, for depletion, interest income and expense, and income taxes.

The Trust uses the accrual basis to recognize revenue, with royalty income recorded as reserves are extracted from the Underlying Properties and sold. Expenses are recognized when paid.

Royalty Interest in Gas Properties:

The Royalty Interests in gas properties are assessed to determine whether their net capitalized cost is impaired, whenever events or changes in circumstances indicate that its carrying amount may not be recoverable, pursuant to Accounting Standards Codification 360, Property, Plant and Equipment ("ASC 360"). The Trust will determine if a write-down is necessary to its investment in the Royalty Interests in gas properties to the extent that total capitalized costs, less accumulated amortization, exceed undiscounted future net revenues attributable to proved gas reserves of the Underlying Properties. Determination as to whether and how much an asset is impaired involves estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on post-production costs and the outlook for national or regional market supply and demand conditions. Estimates of undiscounted future net revenues attributable to proved gas reserves utilize NYMEX forward pricing curves and such undiscounted future net revenues exceed the net royalty interest in gas properties at December 31, 2013. If required, the Trust will provide a write down to the extent that the net capitalized costs exceed the fair value of the investment in net profits interests attributable to proved gas reserves of the Underlying Properties. Any such write-down would not reduce Distributable Income, although it would reduce Trust Corpus. No impairment in the Underlying Properties has been recognized since inception of the Trust. Significant dispositions or abandonment of the Underlying Properties are charged to Royalty Interests and the Trust Corpus.

Amortization of the Royalty Interests in gas properties is calculated on a units-of-production basis, whereby the Trust's cost basis in the properties is divided by Trust total proved reserves to derive an amortization rate per reserve unit. 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.

The conveyance of the Royalty Interests to the Trust was accounted for as a purchase transaction. The $352,100,000 reflected in the Statements of Assets, Liabilities and Trust Corpus as Royalty Interests in Gas Properties represents 17,605,000 Trust Units valued at $20.00 per unit. The carrying value of the Trust's investment in the Royalty Interests is not necessarily indicative of the fair value of such Royalty Interests.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Hedge Contracts

The primary asset of and source of income to the Trust are the Royalty Interests, which generally entitle the Trust to receive varying portions of the net proceeds from gas production from the Underlying Properties. Consequently, the Trust is exposed to market risk from fluctuations in gas prices. Through March 31, 2014, however, the Royalty Interests are subject to the hedge contracts described below, which are expected to reduce the Trust's exposure to natural gas price volatility.

Current hedge contracts consist of natural gas derivative floor price contracts ECA entered into and subsequently conveyed to the Trust to provide the Trust with the economic effects of certain contracts previously entered into between ECA and third parties that equate to approximately 50% of the remaining natural gas originally estimated in connection with the formation of the Trust to be produced by the Trust properties from January 1, 2014 through March 31, 2014. The floor price under the hedging contracts, which will terminate March 31, 2014, is $5.00 per MMBtu.

The following table sets forth the volumes of natural gas covered by the natural gas hedging contracts and the floor price for each quarter during the term of the contracts.

	Swap Volume (MMBtu)	Swap Price (MMBtu)	Floor Volume (MMBtu)	Floor Price (MMBtu)
Second Quarter 2010	682,500	$ 6.75	—	—
Third Quarter 2010	690,000	$ 6.75	—	—
Fourth Quarter 2010	690,000	$ 6.75	225,000	$ 5.00
First Quarter 2011	675,000	$ 6.75	159,000	$ 5.00
Second Quarter 2011	682,500	$ 6.75	210,000	$ 5.00
Third Quarter 2011	690,000	$ 6.82	405,000	$ 5.00
Fourth Quarter 2011	690,000	$ 6.82	384,000	$ 5.00
First Quarter 2012	682,500	$ 6.82	369,000	$ 5.00
Second Quarter 2012	682,500	$ 6.82	516,000	$ 5.00
Third Quarter 2012			1,305,000	$ 5.00
Fourth Quarter 2012			1,362,000	$ 5.00
First Quarter 2013			1,395,000	$ 5.00
Second Quarter 2013			1,380,000	$ 5.00
Third Quarter 2013			1,278,000	$ 5.00
Fourth Quarter 2013			1,188,000	$ 5.00
First Quarter 2014			1,092,000	$ 5.00

The Trust's counterparties under the natural gas floor price contracts are Wells Fargo Capital Finance Inc. and BP Energy Company. In the event that any of the counterparties to the natural gas hedging contracts default on their obligations to make payments to the Trust, the cash distributions to the Trust unitholders would likely be materially reduced as the hedge payments are intended to provide additional cash to the Trust during periods of lower natural gas prices. ECA has no continuing obligations with respect to the natural gas floor price contracts.

Item 8. ***Financial Statements and Supplementary Data.***

Report of Independent Registered Public Accounting Firm

To the Unit Holders of ECA Marcellus Trust I and The Bank of New York Mellon Trust Company, N.A., as Trustee of ECA Marcellus Trust I

We have audited the accompanying statements of assets, liabilities, and trust corpus of ECA Marcellus Trust I as of December 31, 2013 and 2012, and the related statements of distributable income and trust corpus for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

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

As described in Note 3, the financial statements have been prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of ECA Marcellus Trust I as of December 31, 2013 and 2012 and its distributable income for each of the three years in the period ended December 31, 2013—in conformity with the basis of accounting described in Note 3.

We have also audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), ECA Marcellus Trust I's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 Framework) and our report dated March 14, 2014 expressed an unqualified opinion thereon.

Ernst & Young LLP
Pittsburgh, Pennsylvania
March 14, 2014

Report of Independent Registered Public Accounting Firm

To the Unit Holders of ECA Marcellus Trust I and The Bank of New York Mellon Trust Company, N.A., as Trustee of ECA Marcellus Trust I

We have audited ECA Marcellus Trust I's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 Framework) (the COSO criteria). The Trustee of ECA Marcellus Trust I is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Trustee's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with a modified cash basis of accounting, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, ECA Marcellus Trust I maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the statements of assets, liabilities, and trust corpus of ECA Marcellus Trust I as of December 31, 2013 and 2012, and the related statements of distributable income and trust corpus for each of the three years in the period ended December 31, 2013, and our report dated March 14, 2014 expressed an unqualified opinion thereon.

Ernst & Young LLP
Pittsburgh, Pennsylvania
March 14, 2014

ECA Marcellus Trust I

Statements of Assets, Liabilities, and Trust Corpus

As of December 31,

	2013	2012
ASSETS:		
Cash	$ 1,488,231	$ 1,955,202
Royalty income receivable	4,915,471	7,081,475
Floor price contracts	480,480	2,786,520
Royalty interest in gas properties	352,100,000	352,100,000
Accumulated amortization	(118,145,132)	(87,947,444)
Net royalty interest in gas properties	233,954,868	264,152,556
Total Assets	$ 240,839,050	$ 275,975,753
LIABILITIES AND TRUST CORPUS:		
Liabilities:		
Distributions payable to unitholders	$ 6,372,545	$ 9,009,391
Trust corpus; 17,605,000 common units authorized, issued and outstanding	234,466,505	266,966,362
Total Liabilities and Trust Corpus	$ 240,839,050	$ 275,975,753

See notes to the financial statements.

ECA Marcellus Trust I

Statements of Distributable Income

	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011
Royalty income	$ 23,471,407	$ 23,150,405	$ 34,847,366
Hedge proceeds	7,050,579	13,245,734	8,684,531
Net proceeds to Trust	$ 30,521,986	$ 36,396,139	$ 43,531,897
General and administrative expense	(1,069,899)	(1,284,906)	(1,638,768)
Interest income	51	950	947
Income available for distribution prior to cash reserves	$ 29,452,138	$ 35,112,183	$ 41,894,076
Cash reserves released by Trustee	—	500,000	—
Distributable income available to unitholders	$ 29,452,138	$ 35,612,183	$ 41,894,076
Distributable income per common unit (17,605,000 common units authorized and outstanding for 2013; 13,203,750 for 2012 and 2011)	$ 1.673	$ 2.482	$ 2.379
Distributable income per subordinated unit (Zero outstanding for 2013; 4,401,250 subordinated units authorized and outstanding for 2012 and 2011)	$ —	$ 0.644	$ 2.379

See notes to the financial statements.

ECA Marcellus Trust I

Statements of Trust Corpus

	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011
Trust Corpus, Beginning of Period	$ 266,966,362	$ 304,853,821	$ 337,653,898
Cash reserves (released) withheld	—	(500,000)	—
Distributed to ECA	—	—	(10)
Distributable income	29,452,138	35,612,183	41,894,076
Distributions paid or payable to unitholders	(29,448,267)	(35,603,650)	(41,882,678)
Amortization of royalty interest in gas properties	(30,197,688)	(40,791,032)	(32,301,945)
Amortization of floor price contracts	(2,306,040)	(1,562,880)	(509,520)
Write-off of floor premiums payable	—	4,957,920	—
Trust Corpus, End of Period	$ 234,466,505	$ 266,966,362	$ 304,853,821

See notes to the financial statements.

ECA MARCELLUS TRUST I

NOTES TO AUDITED FINANCIAL STATEMENTS

NOTE 1. Organization of the Trust

ECA Marcellus Trust I is a Delaware statutory trust formed in March 2010 by Energy Corporation of America ("ECA") to own royalty interests in fourteen producing horizontal natural gas wells producing from the Marcellus Shale formation, all of which are online and are located in Greene County, Pennsylvania (the "Producing Wells") and royalty interests in 52 horizontal natural gas development wells subsequently drilled to the Marcellus Shale formation (the "PUD Wells") within the "Area of Mutual Interest," or "AMI", comprised of approximately 9,300 acres held by ECA, of which it owns substantially all of the working interests, in Greene County, Pennsylvania. The effective date of the Trust was April 1, 2010; consequently, the Trust received the proceeds of production attributable to the PDP Royalty Interest (defined herein) from that date even though the PDP Royalty Interest was not conveyed to the Trust until the closing of the initial public offering on July 7, 2010. The total number of units the Trust is authorized to issue is 17,605,000 units, all of which are now common units. Prior to December 31, 2012, 13,203,750 were common units and 4,401,250 were subordinated units. The royalty interests were conveyed from ECA's working interest in the Producing Wells and the PUD Wells limited to the Marcellus Shale formation (the "Underlying Properties"). The royalty interest in the Producing Wells (the "PDP Royalty Interest") entitles the Trust to receive 90% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of production of natural gas attributable to ECA's interest in the Producing Wells. The royalty interest in the PUD Wells (the "PUD Royalty Interest" and collectively with the PDP Royalty Interest, the "Royalty Interests") entitles the Trust to receive 50% of the proceeds (exclusive of any production or development costs but after deducting post-production costs and any applicable taxes) from the sale of production of natural gas attributable to ECA's interest in the PUD Wells. As of the formation of the Trust, approximately 50% of the originally estimated natural gas production attributable to the Trust's Royalty Interests had been hedged with a combination of floors and swaps through March 31, 2014. The floor price contracts were transferred to the Trust by ECA, while ECA entered into a back-to-back swap agreement with the Trust to provide the Trust with the benefit of swap contracts entered into between ECA and third parties.

ECA was obligated to drill all of the PUD Wells no later than March 31, 2014. As of November 30, 2011, ECA had met its drilling obligation and had drilled 52.06 Equivalent PUD Wells, calculated as provided in the Development Agreement. Consequently, the drilling support lien ECA had granted to the Trust in connection with the formation of the Trust to secure ECA's drilling obligations has been released. The Trust was not responsible for any costs related to the drilling of development wells or any other development or operating costs. The Trust's cash receipts in respect of the Royalty Interests are determined after deducting post-production costs and any applicable taxes associated with the PDP and PUD Royalty Interests. The Trust's cash available for distribution includes any cash receipts from the floor price contracts and is reduced by Trust administrative expenses. Post-production costs generally consist of costs incurred to gather, compress, transport, process, treat, dehydrate and market the natural gas produced. Charges (the "Post-Production Services Fee") payable to ECA for such post-production costs on the Greene County Gathering System were limited to $0.52 per MMBtu gathered until ECA fulfilled its drilling obligation (which it did in November 2011); thereafter, ECA may increase the Post-Production Services Fee to the extent necessary to recover certain capital expenditures in the Greene County Gathering System. Additionally, in the event that electric compression is utilized in lieu of gas as fuel in the compression process, the Trust will be charged for the electric usage as provided for in the Trust conveyance documents.

ECA MARCELLUS TRUST I

NOTES TO AUDITED FINANCIAL STATEMENTS (Continued)

NOTE 1. Organization of the Trust (Continued)

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting Trust administrative expenses, including the costs incurred as a result of being a publicly traded entity, on or about 60 days following the completion of each quarter. The Trust will liquidate on or about March 31, 2030 (the "Termination Date"). At the Termination Date, 50% of each of the PDP Royalty Interest and the PUD Royalty Interest will revert automatically to ECA. The remaining 50% of each of the PDP Royalty Interest and the PUD Royalty Interest will be sold, and the net proceeds will be distributed pro rata to the unitholders soon after the Termination Date. ECA will have a right of first refusal to purchase the remaining 50% of the Royalty Interests at the Termination Date.

In order to provide support for cash distributions on the common units, ECA agreed during the Subordination Period to subordinate 4,401,250 of the Trust units it originally acquired, which constituted 25% of the outstanding Trust units. 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 which was at least equal to the applicable quarterly subordination threshold. However, if there was not sufficient cash to fund such a distribution on all Trust units, the distribution with respect to the subordinated units was 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 these Trust units, and in order to provide additional financial incentive to ECA to perform its drilling obligation and operations on the Underlying Properties in an efficient and cost-effective manner, ECA 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 exceeded 150% of the subordination threshold for such quarter. ECA's right to receive the incentive distributions terminated upon the expiration of the Subordination Period.

ECA completed its drilling obligation to the Trust during the fourth quarter of 2011. Consequently, the subordinated units automatically converted into common units on a one-for-one basis on December 31, 2012. Holders of common units no longer have any right to the benefits of the subordination provisions that had been in effect with respect to the subordinated units. The period during which the subordinated units were outstanding is referred to as the "Subordination Period."

The business and affairs of the Trust are administered by The Bank of New York Mellon Trust Company, N.A. as Trustee. Although ECA operates all of the Producing Wells and all of the PUD Wells, ECA has no ability to manage or influence the management of the Trust. Neither the Trust nor the Trustee has any authority or responsibility for, or any involvement with or influence over, any aspect of the operations on or relating to the properties to which the Royalty Interests relate.

NOTE 2. Basis of Presentation

The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Without limiting the foregoing statement, the information furnished is based upon certain estimates of the revenues attributable to the Trust from natural gas production for the years ended December 31, 2013, 2012 and 2011 and is therefore subject to adjustment in future periods to reflect actual production for the periods presented.

ECA MARCELLUS TRUST I

NOTES TO AUDITED FINANCIAL STATEMENTS (Continued)

NOTE 3. Significant Accounting Policies

The accompanying audited financial information has been prepared by the Trustee in accordance with the instructions to Form 10-K. The financial statements of the Trust differ from financial statements prepared in accordance with generally accepted accounting principles in the United States of America ("GAAP") because certain cash reserves may be established for contingencies, which would not be accrued in financial statements prepared in accordance with GAAP. Amortization of expired floor price contract premiums does not reduce Distributable Income, rather it is charged directly to Trust Corpus. Amortization of the investment in overriding royalty interests calculated on a unit-of-production basis is charged directly to Trust Corpus. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission as specified by FASB ASC Topic 932 Extractive Activities—Oil and Gas: Financial Statements of Royalty Trusts. Income determined on the basis of GAAP would include all expenses incurred for the period presented. However, the Trust serves as a pass-through entity, with expenses for depreciation, depletion, and amortization, interest and income taxes being based on the status and elections of the Trust unitholders. General and administrative expenses, production taxes or any other allowable costs are charged to the Trust only when cash has been paid for those expenses. In addition, the Royalty Interest is not burdened by field and lease operating expenses. Thus, the statement shows distributable income, defined as income of the Trust available for distribution to the Trust unitholders before application of those additional expenses, if any, for depreciation, depletion, and amortization, interest and income taxes. The revenues are presented net of existing royalties and overriding royalties and have been reduced by gathering/post-production expenses.

Cash:

Cash may include highly liquid instruments maturing in three months or less from the date acquired.

Use of Estimates in the Preparation of Financial Statements:

The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue and Expenses:

The Trust serves as a pass-through entity, with items of depletion, interest income and expense, and income tax attributes being based upon the status and election of the unitholders. Thus, the Statements of Distributable Income show Income available for distribution before application of those unitholders' additional expenses, if any, for depletion, interest income and expense, and income taxes.

The Trust uses the accrual basis to recognize revenue, with royalty income recorded as reserves are extracted from the Underlying Properties and sold. Expenses are recognized when paid.

Royalty Interest in Gas Properties:

The Royalty Interests in gas properties are assessed to determine whether their net capitalized cost is impaired, whenever events or changes in circumstances indicate that its carrying amount may not be recoverable, pursuant to Accounting Standards Codification 360, Property, Plant and Equipment ("ASC 360"). The Trust will determine if a write-down is necessary to its investment in the Royalty

ECA MARCELLUS TRUST I

NOTES TO AUDITED FINANCIAL STATEMENTS (Continued)

NOTE 3. Significant Accounting Policies (Continued)

Interests in gas properties to the extent that total capitalized costs, less accumulated amortization, exceed undiscounted future net revenues attributable to proved gas reserves of the Underlying Properties. Determination as to whether and how much an asset is impaired involves estimates on highly uncertain matters such as future commodity prices, the effects of inflation and technology improvements on post-production costs and the outlook for national or regional market supply and demand conditions. Estimates of undiscounted future net revenues attributable to proved gas reserves utilize NYMEX forward pricing curves and such undiscounted future net revenues exceed the net royalty interest in gas properties at December 31, 2013. If required, the Trust will provide a write-down to the extent that the net capitalized costs exceed the fair value of the investment in net profits interests attributable to proved gas reserves of the Underlying Properties. Any such write-down would not reduce Distributable Income, although it would reduce Trust Corpus. No impairment in the Underlying Properties has been recognized since inception of the Trust. Significant dispositions or abandonment of the Underlying Properties are charged to Royalty Interests and the Trust Corpus.

Amortization of the Royalty Interests in gas properties is calculated on a units-of-production basis, whereby the Trust's cost basis in the properties is divided by Trust total proved reserves to derive an amortization rate per reserve unit. 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.

The conveyance of the Royalty Interests to the Trust was accounted for as a purchase transaction. The $352,100,000 reflected in the Statements of Assets, Liabilities and Trust Corpus as Royalty Interests in Gas Properties represents 17,605,000 Trust Units valued at $20.00 per unit. The carrying value of the Trust's investment in the Royalty Interests is not necessarily indicative of the fair value of such Royalty Interests.

NOTE 4. Commodity Hedges

The Trust is exposed to risk fluctuations in energy prices in the normal course of operations. ECA conveyed to the Trust natural gas derivative floor price contracts and entered into a back-to-back swap agreement with the Trust which conveyed the benefit of certain swap agreements which ECA had previously entered into with third parties. The volumes covered by these agreements equate to approximately 50% of the originally estimated natural gas to be produced by the Trust properties through March 31, 2014. The swap contracts, which expired on June 30, 2012, related to approximately 7,500 MMBtu per day at a weighted average price of $6.78 per MMBtu for the period from April 1, 2010 through June 30, 2012. The price of the floor hedging contracts is $5.00 per MMBtu on a total volume of 11,268,000 MMBtu for the period from October 1, 2010 through March 31, 2014. The Trust uses the cash method to account for commodity contracts. Under this method, gains or losses associated with the contracts are recognized at the time the hedged production occurs. Hedge proceeds realized for the years ended December 31, 2013, 2012 and 2011 totaled $7,050,579, $13,245,734 and $8,684,531, respectively. The fair market values of the commodity contracts are not included in the accompanying financial statements, as the statements are presented on a modified cash basis of accounting.

ECA MARCELLUS TRUST I

NOTES TO AUDITED FINANCIAL STATEMENTS (Continued)

NOTE 5. Income Taxes

The Trust is a Delaware statutory trust, which is taxed as a partnership for federal and state income taxes. Accordingly, no provision for federal or state income taxes has been made. Uncertain tax positions are accounted for under ASC 740, *Income Taxes* (ASC 740), which prescribes a recognition threshold and measurement attribute for financial statement disclosure of tax positions taken or expected to be taken on a tax return. Additionally, ASC 740 provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The Trust has not identified any uncertain tax positions during the year ended December 31, 2013 or 2012.

NOTE 6. Related Party Transactions

Trustee Administrative Fee:

Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $150,000 to the Trustee, which may be adjusted beginning on the fifth anniversary of the Trust as provided in the Trust Agreement. These costs, as well as those to be paid to ECA pursuant to the Administrative Services Agreement referred to below, are deducted by the Trust in the period paid.

Administrative Services Fee:

The Trust has an Administrative Services Agreement with ECA that obligates the Trust to pay ECA each quarter an administrative services fee for accounting, bookkeeping and informational services to be performed by ECA on behalf of the Trust relating to the Royalty Interests. The annual fee of $60,000 is payable in equal quarterly installments. Under certain circumstances, ECA and the Trustee each may terminate the Administrative Services Agreement at any time following delivery of notice no less than 90 days prior to the date of termination.

Drilling Support Lien:

As described in Note 1, ECA granted to the Trust the Drilling Support Lien. The Drilling Support Lien was limited to $91 million, and as ECA fulfilled its drilling obligation over time, the total dollar amount was proportionately reduced. As of November 30, 2011, ECA had fulfilled its drilling obligation and has received a full release of the Drilling Support Lien.

Related Party Ownership and Registration Rights Agreement:

Pursuant to the terms of the Registration Rights Agreement to which ECA and the Trust are parties, ECA and the Trust have filed a registration statement on Form S-3 pursuant to which ECA may publicly offer and sell up to 4,573,128 common units. ECA and the Trust also filed a registration statement on Form S-4 pursuant to which ECA may publicly offer to exchange up to 3,957,527 depositary units of Eastern American Natural Gas Trust for up to 4,120,059 common units of the Trust. The registration statements were declared effective on February 8, 2013. In March 2013, ECA exchanged 1,288,456 common units of the Trust for 946,750 Depositary Units of Eastern American Natural Gas Trust that had been validly tendered for exchange under the registration statement on Form S-4. As of December 31, 2013, ECA held a total of 2,268,401 (approximately 12.9%) of the outstanding common units of the Trust.

ECA MARCELLUS TRUST I

NOTES TO AUDITED FINANCIAL STATEMENTS (Continued)

NOTE 6. Related Party Transactions (Continued)

Supplemental Reserve Information (Unaudited):

Information regarding estimates of the proved gas reserves attributable to the Trust is based on reports prepared by independent petroleum engineering consultants. Such estimates were prepared in accordance with guidelines established by the Securities and Exchange Commission. Accordingly, the estimates were based on existing economic and operating conditions. Numerous uncertainties are inherent in estimating reserve volumes and values and such estimates are subject to change as additional information becomes available.

The reserves actually recovered and the timing of production of these reserves may be substantially different from the original estimates.

The standardized measure of discounted future net cash flows was determined based on reserve estimates prepared by the independent petroleum engineering consultants, Ryder Scott Company, L.P.

The following table reconciles the estimated quantities of the proved natural gas reserves attributable to the Trust's interest from January 1, 2011 to December 31, 2013:

	Natural Gas (MMcf)
Proved reserves:	
Balance at January 1, 2011	102,449
Revisions of previous estimates	(10,918)
Production	(9,813)
Balance at December 31, 2011	81,718
Revisions of previous estimates	(2,255)
Production	(10,931)
Balance at December 31, 2012	68,532
Revisions of previous estimates	(244)
Production	(7,835)
Balance at December 31, 2013	60,453

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Reserves:

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with the provisions of FASB ASC topic Extractive Activities—Oil and Gas. Future cash inflows were computed by applying hydrocarbon prices based on the average prices during the 12-month period prior to the ending date of the period covered the applicable reserve report, determined as unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual

ECA MARCELLUS TRUST I

NOTES TO AUDITED FINANCIAL STATEMENTS (Continued)

NOTE 6. Related Party Transactions (Continued)

arrangements as required by the SEC regulations. The following is the standardized measure of discounted future net cash flows as of December 31, (in thousands):

	2013	2012	2011
Future cash inflows	$ 223,537	$ 197,648	$ 355,195
Future production taxes	—	—	—
Future production costs	(44,131)	(51,524)	(61,655)
Future net cash flows before discount	179,406	146,124	293,540
10% discount to present value	(91,036)	(67,017)	(128,015)
Standardized measure of discounted future net cash flows(1)	$ 88,370	$ 79,107	$ 165,525

(1) 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 from January 1, 2011 to December 31, 2013 in the standardized measure of discounted future net cash flows relating to proved reserves (in thousands):

Standardized measure, January 1, 2011	$ 231,242
Net proceeds to the Trust	(43,532)
Revisions of previous estimates	(22,117)
Accretion of discount	23,124
Net change in price and production cost	(21,454)
Other	(1,738)
Standardized measure, December 31, 2011	$ 165,525
Net proceeds to the Trust	(36,396)
Revisions of previous estimates	(2,602)
Accretion of discount	16,553
Net change in price and production cost	(61,674)
Other	(2,299)
Standardized measure, December 31, 2012	$ 79,107
Net proceeds to the Trust	(30,522)
Revisions of previous estimates	(360)
Accretion of discount	7,911
Net change in price and production cost	18,664
Other	13,570
Standardized measure, December 31, 2013	$ 88,370

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.***

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and regulations promulgated by the SEC. 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 ECA 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 disclosure.

As of the end of the period covered by this 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 contractual arrangements of the Trust Agreement and the conveyances, the Trustee relies on (i) information provided by ECA, including historical operating data, plans for future operating and capital expenditures, reserve information and information relating to projected production, and (ii) conclusions and reports regarding reserves by the Trust's independent reserve engineers. See "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" in this Annual Report on Form 10-K, for a description of certain risks relating to these arrangements and reliance on information when reported by ECA to the Trustee and recorded in the Trust's results of operation.

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 Rule 13a-15(f) promulgated under the Securities and Exchange Act of 1934, as amended. The Trustee conducted an evaluation of the effectiveness of the Trust's internal control over financial reporting based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 Framework). Based on the Trustee's evaluation under the framework in *Internal Control—Integrated Framework* , the Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2013. The Trustee's assessment of the effectiveness of the Trust's internal control over financial reporting as of December 31, 2013 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report which is included herein on page 59.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Further, the design of disclosure controls and procedures and internal control over financial reporting must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected.

Changes in Internal Control over Financial Reporting. During the quarter ended December 31, 2013, there has been no change in the Trustee's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trustee's internal control over financial reporting relating 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 ECA.

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 of 1934 requires officers, directors and 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 Trust has no officers or directors. The Trustee is not aware of any 10 percent unitholder having failed to comply with all Section 16(a) filing requirements in 2013.

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 bank's code of ethics.

Item 11. *Executive Compensation.*

During the years ended December 31, 2011, 2012 and 2013, the Trustee received administrative fees from the Trust pursuant to the Trust Agreement. 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 and/or Schedule13G and on information from ECA.

Beneficial Owner	Trust Common Units Beneficially Owned	Percent of Class
Energy Corporation of America	2,268,401	12.9

(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 any of its parents, the operation of which may at a subsequent date result in a change of control of the registrant.

Item 13. ***Certain Relationships, Related Transactions and Director Independence.***

Development Agreement

Under the terms of the Development Agreement, ECA was obligated to drill all of the PUD Wells by March 31, 2014. In order to secure the estimated amount of the drilling costs for the Trust's interests in the PUD Wells, ECA granted to the Trust a lien on ECA's interest in the Marcellus Shale formation in the AMI, excluding the Producing Wells and any other wells which were producing and not subject to the Royalty Interests. ECA completed its drilling obligation during the fourth quarter of 2011, and the Trust has released the lien securing the drilling obligation.

Administrative Services

Under the terms of the Administrative Services Agreement, the Trust pays a quarterly administration fee of $15,000 to ECA. General and administrative expenses in the Trust's statements of distributable income for the years ending December 31, 2013, 2012 and 2011 include $60,000 in administrative fees for each year. ECA and the Trustee each may terminate the provisions of the Administrative Services Agreement relating to the provision by ECA of administrative services at any time following delivery of notice no less than 90 days prior to the date of termination; provided, however, that ECA may not terminate the Administrative Services Agreement except in connection with ECA's transfer of some or all of the Subject Interests, as defined in the Conveyances, and then only with respect to the Services to be provided with respect to the Subject Interests being transferred, and only upon the delivery to the Trustee of an agreement of the transferee of such Subject interests reasonably satisfactory to the Trustee in which such transferee assumes the responsibility to perform the Services relating to the Subject Interests being transferred.

Trustee Administration Fee

Under the terms of the Trust Agreement, the Trust pays an annual administrative fee to the Trustee of $150,000, paid in four quarterly installments of $37,500. The Trust also pays an annual administrative fee to the Delaware Trustee of $2,500. General and administrative expenses in the

Trust's statements of distributable income for the twelve months ended December 31, 2013, 2012 and 2011 included administrative fees of $187,500, $150,000 and $150,000, respectively. Any variances from the annual fee are the result of such fees being recorded by the Trust in the period paid rather than in the period incurred.

Registration Rights

In connection with the formation of the Trust, the Trust entered into a registration rights agreement for the benefit of ECA, John Mork and certain of his affiliates in connection with ECA's conveyance to the Trust of the PDP Royalty Interest and the PUD Royalty Interest. In the registration rights agreement, the Trust agreed, for the benefit of ECA, John Mork and certain of his affiliates and any of their transferees (each, a "holder"), to register offering of the Trust units held by any of them. Specifically, the Trust agreed:

- 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 continuously 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).

ECA, John Mork and certain of his affiliates had the right to require the Trust to file no more than three registration statements in aggregate. ECA exercised its right to demand registration of an offering in early 2011. During the fourth quarter of 2012, John Mork and Julie Mork each exercised a right to demand registration in connection with offers to sell or exchange ECT common units. The Trust filed the registration statements as required, and consequently will not be required to effect additional registrations under the registration rights agreement.

Director Independence

The Trust does not have a board of directors.

Item 14. ***Principal Accounting Fees and Services.***

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional service firms and related fees are granted by the Trustee. The Trustee has appointed Ernst & Young LLP as the independent registered public accounting firm to audit the Trust's financial statements for the fiscal year ending December 31, 2014. During fiscal 2013, 2012 and 2011, Ernst & Young LLP served as the Trust's independent registered public accounting firm.

The following table presents the aggregate fees billed to the Trust for the fiscal years ended December 31, 2013, 2012 and 2011 by Ernst & Young LLP:

	2013	2012	2011
Audit fees(1)	$ 130,000	$ 125,000	$ 105,000
Audit -related fees	—	—	—
Tax fees	187,050	220,860	150,000
All other fees	—	—	—
Total fees	$ 317,050	$ 345,860	$ 255,000

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

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements

The following financial statements are set forth under "Financial Statements and Supplementary Data" in Item 8 of this Annual Report on Form 10-K on the pages indicated:

(a)(2) Schedules

Schedules have been omitted because they are not required, not applicable or the information required has been included elsewhere herein.

(a)(3) Exhibits

See Exhibit Index.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

ECA MARCELLUS TRUST I

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

By: /s/ MIKE ULRICH

Mike Ulrich
Vice President

March 14, 2014

The Registrant, ECA Marcellus Trust I, 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.

Appendix A

RYDER SCOTT COMPANY
TBPE FIRM LIC. NO. F-1580
FAX (303) 623-4258
621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

December 11, 2013

ECA Marcellus Trust I
The Bank of New York Mellon Trust Company, N.A.
919 Congress Avenue, Suite 500
Austin, Texas 78701

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain royalty interests of ECA Marcellus Trust I (the Trust) as of December 31, 2013. The Trust was formed by Energy Corporation of America (ECA) to own royalty interests in natural gas properties owned and operated by ECA in the Marcellus Shale formation in Greene County, Pennsylvania. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on December 11, 2013 and presented herein, was prepared for public disclosure by the Trust in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations. The properties evaluated by Ryder Scott represent 100 percent of the total net proved reserves of the Trust as of December 31, 2013.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2013, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Royalty Interests of
ECA Marcellus Trust I

As of December 31, 2013

	Total Proved Producing
Net Remaining Reserves	
Gas—MMCF	60,453
Income Data	
Future Gross Revenue	$ 223,536,951
Deductions	44,130,669
Future Net Income (FNI)	$ 179,406,282
Discounted FNI @ 10%	$ 88,369,670

All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMCF) at the official temperature and pressure bases of 60 degrees Fahrenheit and 14.73 psia.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants. The program was used at the request of the Trust. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is normally presented after the deduction of production taxes but in the State of Pennsylvania, these are zero. Furthermore, the Trust owns only a royalty interest, and the deductions shown as "Other" deductions incorporate the Trust's share of post-production costs including gathering, compression, and transportation fees. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income. Gas reserves account for 100 percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income As of December 31, 2013 Total Proved
5	$ 118,399,134
8	$ 98,333,467
12	$ 80,253,066
15	$ 70,559,475

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.The various proved reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist.The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves. At the request of ECA, the gas volumes included herein assume that any shrinkage attributable to gas consumed in operations is negligible.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations."All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Atthe Trust's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward". The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Provedreserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that "as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease." Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

ECA's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes ofproved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which the Trust ownsan interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission's Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods; (2) volumetric-based methods; and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the "quantities actually recovered are much more likely than not to be achieved." The SEC states that "probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." TheSEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

All of the proved reserves for the properties included herein were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis which utilized extrapolations of historical production and pressure data available through November 2013. The data utilized in this analysis were furnished to Ryder Scott by ECA and were considered sufficient for the purpose thereof.

To estimate economically recoverableproved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those underexisting economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

ECA has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by ECA with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, the Pennsylvania impact fee, other costs such as gathering and/or transportation fees, abandonment costs after salvage, product prices based on the SEC regulations, adjustments or differentials to product prices, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by ECA. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." Inour opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

Our forecasts of future production rates for the producing properties included herein are based on historical performance data and the established decline trend of each well. Future production rates may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

ECAfurnished us with the above mentioned average prices in effect on December 31, 2013. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the "benchmark price" and "price reference" used for the geographic area included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report were furnished to us by ECA. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by ECA to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark price adjusted for differentials and referred to herein as the "average realized price."The average realized price shown in the table below was determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for the geographic area included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Price	Average Realized Price
North America				
United States	Gas	Henry Hub	$3.67/MMBTU	$3.70/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by ECA. They are based on the operating expense reports of ECA and include only those costs directly applicable to the leases or wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. Post-production costs, including gathering, compression, and transportation fees, are shown as "Other" deductions. The costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by ECA. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells. All costs were held constant throughout the life of the properties. It should be noted that the Trust only owns a royalty interest in the subject wells and is only burdened by its share of the previously mentioned post-production costs. The operating expenses supplied by ECA were used only to determine the economic life of each property. It should also be noted that the resulting economic life of each property extended beyond the April 1, 2030 reversion date of the Trust.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world for over seventy-five years. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics.We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to the Trust or ECA. Neither we nor any of our employees have any interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by the Trust.

The Trust makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, the Trust has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statement on Form S-3 of the Trust of the references to our name as well as to the references to our third party report for the Trust, which appears in the December 31, 2013 annual report on Form 10-K of the Trust. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by the Trust.

We have provided the Trust with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by the Trust and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work products used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ STEPHAN E. GARDNER

Stephen E. Gardner, P.E.
Colorado License No. 44720
Vice President

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Stephen E. Gardner is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Gardner, an employee of Ryder Scott Company L.P. (Ryder Scott) since 2006, is a Vice President responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Gardner served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Gardner's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Gardner earned a Bachelor of Science degree in Mechanical Engineering from Brigham Young University in 2001 (summa cum laude). He is a licensed Professional Engineer in the States of Colorado and Texas. Mr. Gardner is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Gardner fulfills. As part of his 2012 continuing education hours, Mr. Gardner attended a six hour conference relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. In May 2012, Mr. Gardner attended the DUO Conference in Denver, Colorado which focused on developed and emerging unconventional oil plays and on current issues in energy. In addition, Mr. Gardner attended an SPEE function regarding valuation metrics in the Bakken play and Permian Basin. Finally, Mr. Gardner completed several days of informal study that included such topics as SPEE Monograph 3, utilization of economics evaluation softwares, and principles of waterflooding.

Based on his educational background, professional training and more than seven years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Gardner has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.

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INDEX TO EXHIBITS

Exhibit Number		Description
3.1	—	Certificate of Trust of ECA Marcellus Trust I (Incorporated herein by reference to Exhibit 3.1 to Registration Statement on Form S-1 (Registration No. 333-165833)).
3.2	—	Amended and Restated Trust Agreement of ECA Marcellus Trust I, dated July 7, 2010, among Energy Corporation of America and The Bank of New York Mellon Trust Company, N.A., as Trustee, and Corporation Trust Company, as Delaware Trustee (Incorporated herein by reference to Exhibit 3.1 to the Trust's Current Report on Form 8-K filed on July 13, 2010 (File No. 001-34800)).
10.1(1)	—	Perpetual Overriding Royalty Interest Conveyance (PDP), dated effective April 1, 2010, from Energy Corporation of America to The Bank of New York Mellon Trust Company, N.A., as Trustee.
10.2(1)	—	Perpetual Overriding Royalty Conveyance (PUD), dated effective April 1, 2010, from Energy Corporation of America to The Bank of New York Mellon Trust Company, N.A., as Trustee.
10.3(1)	—	Private Investor Conveyance, dated July 7, 2010, among ECA Marcellus Trust I and certain private investors named therein.
10.4(1)	—	Assignment of Royalty Interest, dated effective April 1, 2010, from Eastern Marketing Corporation to The Bank of New York Mellon Trust Company, N.A., as Trustee.
10.5(1)	—	Term Overriding Royalty Interest Conveyance (PDP), dated effective April 1, 2010 from Energy Corporation of America to Eastern Marketing Corporation.
10.6(1)	—	Term Overriding Royalty Conveyance (PUD), dated effective April 1, 2010, from Energy Corporation of America to Eastern Marketing Corporation.
10.7(1)	—	Administrative Services Agreement, dated July 7, 2010, between Energy Corporation of America and The Bank of New York Mellon Trust Company, N.A., as Trustee.
10.8(1)	—	Development Agreement, dated July 7, 2010, between Energy Corporation of America and The Bank of New York Mellon Trust Company, N.A., as Trustee.
10.9(1)	—	Swap Agreement, dated July 7, 2010, between Energy Corporation of America and ECA Marcellus Trust I.
10.10(1)	—	Drilling Support Lien, dated July 7, 2010, by and between Energy Corporation of America and The Bank of New York Mellon Trust Company, N.A., as Trustee.
10.11(1)	—	Royalty Interest Lien, dated July 7, 2010, by and between Energy Corporation of America and The Bank of New York Mellon Trust Company, N.A., as Trustee.
10.12(1)	—	Registration Rights Agreement, dated July 7, 2010, by and among ECA Marcellus Trust I, Energy Corporation of America, and certain affiliates of Energy Corporation of America.
10.13	—	Underwriting Agreement dated as of July 1, 2010, by and among Energy Corporation of America, ECA Marcellus Trust I, and the underwriters named therein (incorporated herein by reference to exhibit 1.1 to the Trust's Current Report on Form 8-K filed on July 6, 2010 (File No. 001-34800).
10.14	—	Underwriting Agreement dated as of April 12, 2011, by and among Energy Corporation of America, ECA Marcellus Trust I, and the underwriters named therein (incorporated herein by reference to exhibit 1.1 to the Trust's Current Report on Form 8-K filed on April 15, 2011 (File No. 001-34800).

Exhibit Number		Description
23.1*	—	Consent of Ernst & Young LLP
23.2*	—	Consent of Ryder Scott Company, L.P.
31*	—	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32*	—	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	—	Report of Ryder Scott Company, L.P. dated December 11, 2013 (incorporated by reference to Appendix A to this Annual Report on Form 10-K for the year ended December 31, 2013 [File No. 001-34800])

(1) Exhibit previously filed with the SEC and incorporated herein by reference to the exhibit of like designation filed with the Trust's Current Report on Form 8-K filed on July 13, 2010 (File No. 001-34800).

* Filed herewith.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statement (Form S-3 No. 333-185396-01) of ECA Marcellus Trust I of our reports dated March 14, 2014, with respect to the financial statements of ECA Marcellus Trust I, and the effectiveness of internal control over financial reporting of ECA Marcellus Trust I, included in this Annual Report (Form 10-K) for the year ended December 31, 2013.

/s/ Ernst & Young LLP

Ernst & Young LLP

Pittsburgh, Pennsylvania
March 14, 2014

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Exhibit 23.2

CONSENT OF RYDER SCOTT

We hereby consent to the incorporation by reference of our report dated December 11, 2013 and filed as exhibit 99.1 to the Annual Report on Form 10-K for the year ended December 31, 2013 (the "Annual Report") of ECA Marcellus Trust I (the "Trust") into the Registration Statements of the Trust on Form S-3 (Registration No. 333-185396) and to the references to our firm in the Annual Report.

/s/ Ryder Scott Company

Ryder Scott Company

Denver, Colorado
March 14, 2014

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Exhibit 23.2

CONSENT OF RYDER SCOTT

Exhibit 31

CERTIFICATION

I, Mike Ulrich, certify that:

1. I have reviewed this report on Form 10-K of ECA Marcellus Trust I, for which The Bank of New York Mellon Trust Company, N.A. acts as Trustee;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, distributable income and changes in Trust corpus of the registrant as of, and for, the periods presented in this report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(c) and 15d-15(f)), or for causing such controls and procedures to be established and maintained, for the registrant and I have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this report is being prepared; and

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the basis of accounting described in Note 3; and

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected or is reasonably likely to materially affect the registrant's internal control over financial reporting; and

5. I have disclosed, based on my most recent evaluation, to the registrant's auditors:

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report information; and

   (b) Any fraud, whether or not material, that involves any persons who have a significant role in the registrant's internal control over financial reporting.

In giving the foregoing certifications in paragraphs 4 and 5 I have relied to the extent I consider reasonable on information provided to me by Energy Corporation of America.

Date: March 14, 2014

/s/ MIKE ULRICH

Mike Ulrich
Vice President and Trust Officer
The Bank of New York Mellon Trust Company, N.A.

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Exhibit 32

March 14, 2014
Via EDGAR
Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549

Re: Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

Ladies and Gentlemen:

In connection with the Annual Report of ECA Marcellus Trust I (the "Trust") on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, not in its individual capacity but solely as the Trustee of the Trust, certifies pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to its knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Trust.

The above certification is furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350) and is not being filed as part of the Form 10-K or as a separate disclosure document.

The Bank of New York Mellon Trust Company,
N.A., Trustee for ECA Marcellus Trust I

By: /s/ MIKE ULRICH

Mike Ulrich
Vice President and Trust Officer

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Exhibit 32