ECA Marcellus Trust I
Form 10-Q
August 09, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

for the quarterly period ended June 30, 2012

OR

o 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)

1-800-852-1422
(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

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 o No o

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 o	Accelerated filer x
Non-accelerated filer o	Smaller reporting company o
(Do not check if a smaller reporting company)	

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

As of August 9, 2012, 13,203,750 Common Units and 4,401,250 Subordinated Units of Beneficial Interest in ECA Marcellus Trust I were outstanding.

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PART I-FINANCIAL INFORMATION

Item 1. ***Financial Statements.***

ECA Marcellus Trust I

Statements of Assets, Liabilities, and Trust Corpus

(Unaudited)

	As of June 30, 2012	As of December 31, 2011
ASSETS:		
Cash	$ 1,046,391	$ 985,425
Royalty income receivable	4,173,231	7,740,789
Hedge proceeds receivable	3,141,780	2,256,803
Floor price contracts	3,960,000	4,349,400
Royalty interest in gas properties	352,100,000	352,100,000
Accumulated amortization	(67,161,450)	(47,156,412)
Net royalty interest in gas properties	284,938,550	304,943,588
Total Assets	$ 297,259,952	$ 320,276,005
LIABILITIES AND TRUST CORPUS:		
Liabilities:		
Floor premiums payable	$ 4,957,920	$ 4,957,920
Distributions payable to unitholders	8,334,483	10,464,264
Trust corpus; 13,203,750 common units and 4,401,250 subordinated units authorized, issued and outstanding	283,967,549	304,853,821
Total Liabilities and Trust Corpus	$ 297,259,952	$ 320,276,005

See notes to the unaudited financial statements.

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ECA Marcellus Trust I

Statements of Distributable Income

(Unaudited)

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011
Royalty income	$ 9,774,726	$ 17,814,285	$ 4,173,231	$ 9,909,451
Hedge proceeds	8,198,824	3,735,436	4,576,948	1,805,863
Net proceeds to Trust	$ 17,973,550	$ 21,549,721	$ 8,750,179	$ 11,715,314
General and administrative expense	(948,409)	(1,203,614)	(415,902)	(601,408)
Interest income	424	447	206	242
Income available for distribution prior to cash reserves and incentive calculation	$ 17,025,565	$ 20,346,554	$ 8,334,483	$ 11,114,148
Cash reserves released by Trustee	500,000			
Distributable income available to unitholders	$ 17,525,565	$ 20,346,554	$ 8,334,483	$ 11,114,148
Distributable income per common unit (13,203,750 common units authorized and outstanding)	$ 1.176	$ 1.155	$ 0.602	$ 0.631
Distributable income per subordinated unit (4,401,250 subordinated units authorized and outstanding)	$ 0.454	$ 1.155	$ 0.088	$ 0.631

See notes to the unaudited financial statements.

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ECA Marcellus Trust I

Statements of Trust Corpus

(Unaudited)

	Six Months Ended June 30, 2012	2011
Trust Corpus, Beginning of Period	$ 304,853,821	$ 337,653,898
Cash reserves released	(500,000)	
Distributed to ECA		(10)
Distributable income	17,525,565	20,346,554
Distributions paid or payable to unitholders	(17,517,399)	(20,332,656)
Amortization of royalty interest in gas properties	(20,005,038)	(15,173,210)
Amortization of floor price contracts	(389,400)	(162,360)
Trust Corpus, End of Period	$ 283,967,549	$ 322,332,216

See notes to the unaudited financial statements.

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ECA MARCELLUS TRUST I

NOTES TO FINANCIAL STATEMENTS

(Unaudited)

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 to be 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 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, of which 13,203,750 are common units and 4,401,250 are 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 is entitled to recoup its costs of establishing the floor price contracts only if and to the extent cash available for distribution by the Trust exceeds certain levels during the Subordination Period.

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 royalties 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 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 (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.

Generally, the percentage of production proceeds to be received by the Trust with respect to a well will equal 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

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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 expects to make quarterly cash distributions of substantially all of its cash receipts, after deducting Trust administrative expenses on or about 60 days following the completion of each quarter through (and including) the quarter ending March 31, 2030 (the Termination Date). The first quarterly distribution was made on August 31, 2010 to record unitholders as of August 16, 2010. The Trust will begin to liquidate on the Termination Date and will soon thereafter wind up its affairs and terminate. 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 has agreed to subordinate 4,401,250 of the Trust units it originally acquired, which constitute 25% of the outstanding Trust units. The subordinated units are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units which is at least equal to the applicable quarterly subordination threshold. However, if there is not sufficient cash to fund such a distribution on all Trust units, the distribution with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. In exchange for agreeing to subordinate 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 is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter exceeds 150% of the subordination threshold for such quarter. ECA s right to receive the incentive distributions will terminate upon the expiration of the Subordination Period.

ECA incurred costs of approximately $5.0 million for floor price contracts that were transferred to the Trust. ECA is entitled to reimbursement for these expenditures plus interest accrued at 10% per annum (Reimbursement Amount) only if and to the extent distributions to Trust unitholders would otherwise exceed the incentive threshold. This Reimbursement Amount will be deducted, over time, from the 50% of cash available for distribution in excess of the incentive thresholds otherwise payable to the Trust unitholders.

ECA completed its drilling obligation to the Trust during the fourth quarter of 2011. Consequently, the subordinated units will automatically convert into common units on a one-for-one basis and ECA s right to receive incentive distributions and to recoup the Reimbursement Amount will terminate on December 31, 2012. Accordingly, ECA bears the risk that it will not be fully or even partially reimbursed for its expenses relating to the floor price contracts transferred to the Trust. Further, once the subordinated units convert to common units on December 31, 2012, holders of common units will no longer have any right to the benefits of the subordination provisions currently in effect with respect to the Subordinated Units. The period during which the subordinated units are outstanding is referred to as the Subordination Period.

The business and affairs of the Trust are managed by The Bank of New York Mellon Trust Company, N.A. as Trustee. Although ECA operates all of the Producing Wells and substantially 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 the properties to which the Royalties 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 disclosures 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

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Trust from natural gas production for the three months and six months ended June 30, 2012 and 2011 and is therefore subject to adjustment in future periods to reflect actual production for the periods presented.

The information furnished reflects all normal and recurring adjustments which are, in the opinion of the Trustee, necessary for a fair presentation of the results for the interim period presented. The accompanying unaudited interim financial statements should be read in conjunction with the audited financial statements and notes thereto included in the Trust s Annual Report on Form 10-K for the year ended December 31, 2011. The year-end condensed balance sheet data was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America.

NOTE 3. Significant Accounting Policies

The accompanying unaudited financial information has been prepared by the Trustee in accordance with the instructions to Form 10-Q. 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 purports to show 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 reflected net of existing royalties and overriding royalties and have been reduced by gathering/post-production expenses.

Cash:

Cash consists of highly liquid instruments with maturities at the time of acquisition of three months or less.

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 purport to 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 of accounting 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 - Topic 360, Property, Plant and Equipment (ASC 360). The Trust will

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determine if a writedown 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 operating expenses and the outlook for national or regional market supply and demand conditions. The Trust will then provide a writedown 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 writedown 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.

Accrued Interest Payable:

Accrued interest payable to ECA by the Trust is calculated at 10% per annum on the outstanding balance of the floor contract premiums payable, but is not recorded by the Trust until paid. As of June 30, 2012, the amount of unrecorded accrued interest payable to ECA was $1,056,844.

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, relate 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 quarters ended June 30, 2012 and 2011 totaled $4,576,948 and $1,805,863, respectively. Hedge proceeds realized for the six months ended June 30, 2012 and 2011 totaled $8,198,824 and $3,735,436, 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.

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.

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.

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These costs, as well as those to be paid to ECA pursuant to the Administrative Services Agreement referred to below, will be deducted by the Trust in the period paid.

Administrative Services Fee:

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 Royalties. 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:

In May 2012, ECA sold 443,723 of its original subordinated Trust units in a private transaction. As of June 30, 2012, ECA held a total of 180,958 Common Units and 3,957,527 subordinated units of the Trust.

Item 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations.***

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, include the Private Investors. The following review of the Trust s financial condition and results of operations should be read in conjunction with the financial statements and notes thereto, as well as the Discussion and Analysis of Historical Results from the Producing Wells contained in the Prospectus. The Trust s Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports are available on the SEC s website at www.sec.gov and also at www.businesswire.com/cnn/ect.htm.

Results of Trust Operations

For the Three Months Ended June 30, 2012 compared to the Three Months Ended June 30, 2011

Distributable income for the three months ended June 30, 2012 decreased to $8.3 million from $11.1 million for the three months ended June 30, 2011. Compared to the quarter ended June 30, 2011, royalty income decreased $5.7 million, hedge proceeds increased $2.8 million and general and administrative expenses decreased $0.2 million.

Royalty income decreased from $9.9 million for the three months ended June 30, 2011 to $4.2 million for the three months ended June 30, 2012, a decrease of $5.7 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 three months ended June 30, 2012 declined $1.39 per Mcf to $3.27 per Mcf as compared to $4.66 per Mcf for the three months ended June 30, 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 $4.59

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per Mcf for the three months ended June 30, 2011 to $2.31 per Mcf for the three months ended June 30, 2012. This decrease in price was primarily the result of a decline in the weighted average monthly closing NYMEX price for the current quarter to $2.21 per Dth compared to the quarter ended June 30, 2011 weighted average monthly closing NYMEX price of $4.32 per Dth.

Post production costs, which consisted of a gathering fee together with a charge for electric 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 quarter ended June 30, 2012 as compared to an average of $0.64 per Mcf for the prior year s comparable quarter. Post production costs were higher than the previous year s quarter as a result of firm transportation charges on the Columbia Gas Transmission, L.L.C. interstate pipeline system beginning in August 2011, resulting in an average $0.15 per Mcf increase in costs from the comparable quarter in 2011. This was partially offset by an average $0.04 per Mcf decline in the charge for electric usage from the quarter ended June 30, 2011 to the current quarter.

Production increased 7% from 2,512 MMcf for the three months ended June 30, 2011 to 2,679 MMcf for the three months ended June 30, 2012. The increased production was primarily a result of an increase in the number of wells online and producing during the quarter ended June 30, 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 June 30, 2012, while there were a total of thirty-one wells (14 PDP and 17 PUD Wells (21.89 Equivalent PUD Wells)) online and producing as of June 30, 2011. Of the forty PUD Wells, six (8.22 Equivalent PUD Wells) of these wells were brought online during the quarter ended June 30, 2012. Three wells (4.02 Equivalent PUD Wells) were brought online in early May and three (4.20 Equivalent PUD Wells) were brought online in mid-June. Subsequently, these six wells (8.22 Equivalent PUD Wells) had an average daily production rate, net to the Trust, of 3,417 Mcf per day for June 2012. Because of gathering system constraints and three of the wells being in production for only a partial month, the average June production rate, as stated, does not represent the full potential of such wells. The average gross initial production for the first thirty days of production for the six wells brought online during the quarter ended June 30, 2012 (8.22 Equivalent PUD Wells) was 2,160 Mcf per well per day.

The Trust had experienced production curtailments during the current period as a result of facility delays while waiting for governmental permits, which have been approved as of June 30, 2012. As a result, production was curtailed due to high operating pressure. The current production was slightly above the design capacity of the Greene County Gathering System and above targeted production that was originally established at the formation of the Trust. The additional gathering systems and/or transportation pipelines were constructed and became operational in late June, allowing increased volumes.

Hedged volumes for the quarter ended June 30, 2012 totaled 1,198,500 Dth consisting of 682,500 Dth covered by a fixed price swap at a price of $6.82 per Dth and 516,000 Dth covered by a $5.00 per Dth floor price contract resulting in an average hedge price of approximately $6.04 per Dth for the hedged volume. For the quarter ended June 30, 2011 hedged volumes totaled 892,500 Dth consisting of 682,500 Dth covered by a fixed price swap at a price of $6.75 per Dth and 210,000 Dth covered by a $5.00 per Dth floor price contract resulting in an average hedge price of approximately $6.34 per Dth for the hedged volume. While this resulted in an increase in total hedge proceeds received by the Trust for the quarter ended June 30, 2012, the average hedge price per Dth declined from $6.34 per Dth for the quarter ended June 30, 2011 to $6.04 per Dth for the quarter ended June 30, 2012 primarily due to a larger floor position.

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 are in effect.

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For the quarter ended June 30, 2012, the distribution available to all Trust units was $8,334,483, or $0.473 per unit. Because the subordination threshold for the quarter was $0.602, common unitholders are entitled to a distribution of $0.602 per unit with the subordinated unitholders entitled to a distribution of the remainder at $0.088 per unit. The table below shows the effect of the subordination threshold:

			For the quarter ended June 30, 2012
Distributable income available to unitholders		$	8,334,483
Common units outstanding	13,203,750		
Subordinated units outstanding	4,401,250		17,605,000
Distributable income per unit before subordination threshold		$	0.473
Subordination threshold per common unit		$	0.602
Common units outstanding			13,203,750
Distributable income payable to common unitholders at subordination threshold level		$	7,948,657
Distributable income available to subordinated unitholders		$	385,826
Subordinated units outstanding			4,401,250
Distributable income per unit available to subordinated unitholders		$	0.088

The Subordination Period will terminate on December 31, 2012.

General and administrative expenses paid by the Trust were $0.4 million for the three months ended June 30, 2012 as compared to $0.6 million for the prior year s comparable quarter. The decrease in expenses was primarily related to a decrease of $0.2 million in state franchise taxes paid. Cash reserves were unchanged during the quarters ended June 30, 2012 and 2011.

ECA completed its drilling obligation as of November 30, 2011. During the quarter ended June 30, 2012, six PUD Wells (8.22 Equivalent PUD Wells) were turned online and producing. As of June 30, 2012, all forty PUD Wells (52.06 Equivalent PUD Wells) were turned online and producing.

For the Six Months Ended June 30, 2012 compared to the Six Months Ended June 30, 2011

Distributable income for the six months ended June 30, 2012 decreased to $17.5 million from $20.3 million for the six months ended June 30, 2011. Compared to the six months ended June 30, 2011, royalty income decreased $8.0 million, hedge proceeds increased $4.5 million, general and administrative expenses decreased $0.3 million and the trustee released $0.5 million of cash reserves during the six months ended June 30, 2012.

Royalty income decreased from $17.8 million for the six months ended June 30, 2011 to $9.8 million for the six months ended June 30, 2012, a decrease of $8.0 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 six months ended June 30, 2012 declined $1.33 per Mcf to $3.35 per Mcf as compared to $4.68 per Mcf for the six months ended June 30, 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

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price. The average sales price, before the effects of hedges and post production costs, declined from $4.51 per Mcf for the six months ended June 30, 2011 to $2.56 per Mcf for the six months ended June 30, 2012. This decrease in price was primarily the result of a decline in the weighted average monthly closing NYMEX price for the current period to $2.47 per Dth compared to the six months ended June 30, 2011 weighted average monthly closing NYMEX price of $4.22 per Dth.

Post production costs, which consisted of a gathering fee together with a charge for electric used in lieu of gas for compression on the gathering system and firm transportation charges on interstate gas pipelines, averaged $0.74 per Mcf for the six months ended June 30, 2012 as compared to an average of $0.65 per Mcf for the prior year s comparable period. Post production costs were higher than the previous year s six-month period as a result of firm transportation charges on the Columbia Gas Transmission, L.L.C. interstate pipeline system beginning in August 2011, resulting in an average $0.15 per Mcf increase in costs from the comparable period in 2011. This was partially offset by an average $0.06 per Mcf decline in the charge for electric usage from the six months ended June 30, 2011 to the current period.

Production increased 16% from 4,609 MMcf for the six months ended June 30, 2011 to 5,361 MMcf for the six months ended June 30, 2012. The increased production was primarily a result of an increase in the number of wells online and producing during the six months ended June 30, 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 June 30, 2012, while there were a total of thirty-one wells (14 PDP and 17 PUD Wells (21.89 Equivalent PUD Wells)) online and producing as of June 30, 2011. Of the forty PUD Wells, nine (12.23 Equivalent PUD Wells) of these wells were brought online during the six months ended June 30, 2012. One well (1.40 Equivalent PUD Wells) was brought online in late January, two (2.61 Equivalent PUD Wells) in early March, three (4.02 Equivalent PUD Wells) in early May, and three (4.20 Equivalent PUD Wells) in mid-June. Subsequently, these nine wells (12.23 Equivalent PUD Wells) had an average daily production rate, net to the Trust, of 4,762 Mcf per day for June 2012. Because of gathering system constraints and three of the wells being in production for only a partial month, the average June production rate, as stated, does not represent the full potential of such wells. The average gross initial production for the first thirty days of production for the nine wells brought online in 2012, (12.23 Equivalent PUD Wells) was 1,914 Mcf per well per day.

The Trust had experienced production curtailments during the current period as a result of facility delays while waiting for governmental permits, which have been approved as of June 30, 2012. As a result, production was curtailed due to high operating pressure. The current production was slightly above the design capacity of the Greene County Gathering System and above targeted production that was originally established at the formation of the Trust. The additional gathering systems and/or transportation pipelines were constructed and became operational in late June, allowing increased volumes.

Hedged volumes for the six months ended June 30, 2012 totaled 2,250,000 Dth consisting of 1,365,000 Dth covered by a fixed price swap at a price of $6.82 per Dth and 885,000 Dth covered by a $5.00 per Dth floor price contract resulting in an average hedge price of approximately $6.10 per Dth for the hedged volume. For the six months ended June 30, 2011 hedged volumes totaled 1,726,500 Dth consisting of 1,357,500 Dth covered by a fixed price swap at a price of $6.75 per Dth and 369,000 Dth covered by a $5.00 per Dth floor price contract resulting in an average hedge price of approximately $6.38 per Dth for the hedged volume. While this resulted in an increase in total hedge proceeds received by the Trust for the six months ended June 30, 2012, the average hedge price per Dth declined from $6.38 per Dth for the six months ended June 30, 2011 to $6.10 per Dth for the six months ended June 30, 2012 primarily due to a larger floor position.

General and administrative expenses paid by the Trust were $0.9 million for the six months ended June 30, 2012 as compared to $1.2 million for the prior year s comparable period. The decrease in expenses was primarily related to a decrease of $0.4 million in state franchise taxes paid and a $0.1 million reduction in non-audit professional fees, partially offset by a $0.2 million increase in audit and tax service fees during the six months ended June 30, 2012. Cash reserves of $0.5 million were released during the six months ended June 30, 2012, which increased distributable income for the period, and were unchanged during the six months ended June 30, 2011.

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ECA completed its drilling obligation as of November 30, 2011. During the six months ended June 30, 2012, nine PUD Wells (12.23 Equivalent PUD Wells) were turned online and producing. As of June 30, 2012, all forty PUD Wells (52.06 Equivalent PUD Wells) were turned online and producing.

Note Regarding Forward-Looking Statements

This Form 10-Q 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 completion and operation of natural gas wells;
- future production and development costs;
- the effects of existing and future laws and regulatory actions;
- the effects of changes in commodity prices;
- the ability of the Trust s hedge counterparties, including ECA, 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 the Trust s Annual Report on Form 10-K for the year ended December 31, 2011.

This Form 10-Q 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.

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 Royalties (described below), to distribute to the Trust unitholders cash that the Trust receives in respect of the Royalties after payment of Trust expenses, and to perform certain administrative functions in respect of the Royalties 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 Royalties relate. The Trust derives all or substantially all of its income and cash flows from the Royalties, which in turn are subject to the hedge contracts described in Part I, Item 3. 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 Subordination Period will terminate on December 31, 2012. As of June 30, 2012 the Trust owns Royalties in the 14 Producing Wells and the forty 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 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, Royalties) 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 PUD wells, even though some or all of the PUD wells may have been drilled and completed and may be producing. As of the formation of the Trust, approximately 50% of the 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. ECA is entitled to recoup its costs of establishing the floor price contracts only if and to the extent cash available for distribution by the Trust exceeds certain levels during the Subordination Period.

ECA was obligated to drill all of the PUD Wells no later than March 31, 2014. As of November 30, 3011, 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 Royalties is determined after deducting post-production costs and any applicable taxes associated with the PDP and PUD Royalty Interests, and the Trust s cash available for distribution will include 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 will equal 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 Well, 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.

Hedge proceeds realized for the quarter ended June 30, 2012 were approximately $4.6 million and approximately $8.2 million for the six months ended June 30, 2012. The swap hedging arrangements terminated June 30, 2012 and 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 are in effect.

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The Trust expects to make 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 through (and including) the quarter ending March 31, 2030 (the Termination Date).

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

- the timing of initial production from the PUD Wells;
- natural gas prices received;
- the volume and Btu rating of natural gas produced and sold;
- post-production costs and any applicable taxes;
- the reimbursement by the Trust, if any, of ECA s costs associated with establishing the floor price contracts transferred to the Trust and interest on such amounts;
- administrative expenses of the Trust and 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. However, in order to provide support for cash distributions on the common units for a limited period of time, ECA has agreed to subordinate 4,401,250 of the Trust units it initially acquired, which constitute 25% of the outstanding Trust units. While the subordinated units will be entitled to receive pro rata distributions from the Trust if and to the extent there is sufficient cash to provide a cash distribution on the common units which is no less than the applicable quarterly subordination thresholds set forth below, if there is not sufficient cash to fund such a distribution on all Trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. ECA completed its drilling obligation during the fourth quarter of 2011 and accordingly, the Subordination Period will expire on December 31, 2012. During the Subordination Period, ECA is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter exceeds 150% of the subordination threshold for such quarter. ECA s right to receive the incentive distributions will terminate upon the expiration of the Subordination Period, which will end on December 31, 2012.

Further, once the subordinated units convert to common units on December 31, 2012, holders of common units will no longer have any right to the benefits of the subordination provisions currently in effect with respect to the Subordinated Units.

ECA incurred costs of approximately $5.0 million for floor price contracts transferred to the Trust. ECA is entitled to reimbursement for these expenditures plus interest accrued at 10% per annum only if and to the extent distributions to Trust unitholders would otherwise exceed the incentive threshold. This reimbursement will be deducted, over time, from the 50% of cash available for distribution in excess of the incentive thresholds otherwise payable to the Trust unitholders. As of June 30, 2012, the amount of unrecorded accrued interest payable to ECA was $1,056,844. This amount is payable solely out of the 50% of cash, if any, available for distribution in excess of the incentive thresholds otherwise payable to the Trust unitholders. Consequently, any such amounts not payable from Trust distributable income through the quarter ending December 31, 2012 will never become payable.

The Subordinated Units will automatically convert into common units on a one-for-one basis and ECA s right to receive incentive distributions and to recoup the Reimbursement Amount will terminate on December 31, 2012.

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The table below sets forth the Target Distribution and the Subordination and Incentive Thresholds for each calendar quarter through the fourth quarter of 2012. The Subordination Period will end on December 31, 2012; consequently there will be no Target Distribution or Subordination or Incentive Thresholds after that date. The Target Distributions were determined in connection with the formation of the Trust solely for the purpose of calculating the Subordination and Incentive Thresholds. They are not projections or estimates of actual distributions.

	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 35% of the distribution made to foreign partners.

ECA has informed the Trustee that it has finalized the completion of the last of the 52 equivalent Development Wells and has finalized the construction of the gathering system expansion project in Greene County, Pennsylvania after receiving the appropriate governmental permits. ECA has further informed the Trustee that total gross initial production from the last three wells completed for the Trust exceeded ten MMcf/day. The gathering system expansion project, which included the addition of a new compressor station, has increased gross field capacity to over 90 MMcf/day, up from the previous limit of 65 MMcf/day. As a result of the gathering system expansion and the completion of the final Development Wells, all of the Trust Wells are now on line and producing, ahead of the previously announced anticipated completion date of the 3rd quarter of 2012, and well ahead of ECA s commitment to complete its drilling obligations by March 31, 2014.

Liquidity and Capital Resources

The Trust has no source of liquidity or capital resources other than cash flows from the Royalties. Other than Trust administrative expenses, including any reserves established by the Trustee for future liabilities, the Trust s only use of cash is for distributions to Trust unitholders, including, if applicable, incentive distributions to ECA and, if applicable, expense reimbursements to ECA. 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 Royalties and other sources (such as interest earned on any amounts reserved by the Trustee) that quarter, over the Trust s expenses for that quarter, subject in all cases to the subordination and incentive provisions described above. 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

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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 Royalties 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.

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 will only be charged to the Trust 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 purports to show 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 purport to 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 - Topic 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. The Trust will then 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.

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

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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 3. Quantitative and Qualitative Disclosures about Market Risk.

Hedge Contracts

The primary asset of and source of income to the Trust is the Royalties, 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 Royalties are subject to the hedge contracts described below, which are expected to reduce the Trust s exposure to natural gas price volatility.

The hedge contracts consist of natural gas derivative floor price contracts and, until June 30, 2012, a back-to-back swap agreement ECA entered into with the Trust to provide the Trust with the benefit of certain contracts previously entered into between ECA and third parties, that equate 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, which expire in the first quarter of 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, and its counterparty under the back-to-back swap agreement, until June 30, 2012, was ECA, whose counterparties were also Wells Fargo Capital Finance Inc. and BP Energy Company. In the event that any of the counterparties to the natural gas hedging contracts defaults on its obligation 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 obligation with respect to the natural gas floor price contracts. However, ECA had been the Trust s counterparty under the

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back-to-back swap agreement, which expired June 30, 2012, and had continuing obligations with respect to this agreement.

Item 4. ***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 forms promulgated by the SEC. Disclosure controls and procedures include 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 Act 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 nature of the Trust, there are certain potential weaknesses that may limit the effectiveness of the disclosure controls and procedures established by the Trustee. The limitations include the facts that:

- ECA and its consolidated subsidiaries manage virtually all of the information relating to the Trust, including all information regarding (i) historical operating data, production volumes, the number of producing wells and acreage, the marketing and sale of production, operating and capital expenditures, environmental matters and other potential expenses and liabilities, and the effects of regulatory matters and changes, (ii) plans for future operating and capital expenditures and (iii) geological data relating to reserves, and the Trustee necessarily relies on ECA for all such information; and

- The Trustee necessarily relies upon the independent reserve engineer as an expert with respect to the annual reserve report, which includes projected production, operating expenses and capital expenses.

Other than reviewing the financial and other information provided to the Trust by ECA and the independent reserve engineer, the Trustee has made no independent or direct verification of this financial or other information.

The Trustee does not intend to expand its responsibilities beyond those permitted or required by the Trust Agreement and those required under applicable law.

The Trustee does not expect that the Trustee s disclosure controls and procedures or the Trustee s internal control over financial reporting will prevent all errors or all fraud. 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 June 30, 2012, there has been no change in the Trustee s internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trustee s internal control over financial reporting 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.

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PART II-OTHER INFORMATION

Item 1A. *Risk Factors.*

Risk factors relating to the Trust are contained in Item 1A of the Trust s Annual Report on Form 10-K for the fiscal year ended December 31, 2011. No material change to such risk factors has occurred during the three months ended June 30, 2012.

Item 6. Exhibits.

The exhibits listed in the accompanying index to exhibits are filed as part of this Quarterly Report on Form 10-Q.

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SIGNATURES

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

ECA MARCELLUS TRUST I

By:	THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., trustee
By:	/s/ MIKE ULRICH Mike Ulrich *Vice President*

Date: August 9, 2012

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.

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EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Trust of ECA Marcellus Trust I (Incorporated herein by reference to Exhibit 3.4 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, by and among Energy Corporation of America, 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*	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*	Perpetual Overriding Royalty Interest 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*	Private Investor Conveyance, dated July 7, 2010, by and among ECA Marcellus Trust I and certain private investors named therein
10.4*	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*	Term Overriding Royalty Interest Conveyance (PDP), dated effective April 1, 2010, from Energy Corporation of America to Eastern Marketing Corporation.
10.6*	Term Overriding Royalty Interest Conveyance (PUD), dated effective April 1, 2010, from Energy Corporation of America to Eastern Marketing Corporation.
10.7*	Administrative Services Agreement, dated July 7, 2010, by and between Energy Corporation of America and The Bank of New York Mellon Trust Company, N.A., as Trustee
10.8*	Development Agreement, dated July 7, 2010, by and between Energy Corporation of America and The Bank of New York Mellon Trust Company, N.A., as Trustee.
10.9*	Swap Agreement, dated July 7, 2010, by and between Energy Corporation of America and ECA Marcellus Trust I.
10.10*	Drilling Support Lien Agreement, dated July 7, 2010, by and between Energy Corporation of America and The Bank of New York Mellon Trust Company, N.A.
10.11*	Royalty Interest Lien Agreement, 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*	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 June 30, 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)).
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

*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).

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APPENDIX A

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.

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.

Dth - means one million British Thermal Units.

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.

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

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 is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter exceeds 150% of the subordination threshold for such quarter. ECA s right to receive the incentive distributions will terminate 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.

Producing Wells - means the 14 natural gas wells located in Greene County, Pennsylvania and described as the Producing Wells 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.

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.

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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 are subject to the subordination provisions described herein. Because ECA met its drilling obligation to the Trust on November 30, 2011, the Subordination Period will expire on December 31, 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 has agreed to subordinate the 4,401,250 Trust units it acquired, which constitute 25% of the outstanding Trust units. While the subordinated units are entitled to receive pro rata distributions from the Trust if and to the extent there is sufficient cash to provide a cash distribution on the common units which is at least equal to the applicable quarterly subordination threshold, if there is not sufficient cash to fund such a distribution on all Trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated in order to make a distribution, to the extent possible, of up to the Subordination Threshold amount on the common units.

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.