EASTERN AMERICAN NATURAL GAS TRUST
Form 10-K
March 12, 2004

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 1O-K

ý	**ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2003**
	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: 1-11748

Eastern American Natural Gas Trust

(Exact name of registrant as specified in its Charter)

Delaware	**36-7034603**
(State or other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

The Bank of New York

Care of BNY Midwest Trust Company

2 North LaSalle Street, Suite 1020

Chicago, Illinois 60602

(Address of principal executive office) (Zip Code)

(312) 827-8500

(Registrant s telephone number, including area code)

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

Title of Each Class	**Name of Each Exchange On Which Registered**
Units of Beneficial Interest	New York Stock Exchange

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

None

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 o No ý

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 the registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ý No o

(1) The Registrant inadvertently did not file reports on Form 8-K for its 2003 quarterly press releases announcing quarterly distributable income and distribution amounts.

As of March 8, 2004, 5,900,000 Units of Beneficial Interest in Eastern American Natural Gas Trust have been issued, remain outstanding and are held by non-affiliates of the registrant (the Outstanding Units). Of the Outstanding Units, 69,900 Units of Beneficial Interest have been withdrawn from trading by voluntary action of Holders and may not be traded unless such Holders comply with certain requirements provided in the related Trust Agreement (the Withdrawn Units).

The aggregate market value of the Outstanding Units minus the Withdrawn Units at the closing sales price on March 8, 2004 of $23.93 was approximately $141 million.

Documents Incorporated By Reference: None

TABLE OF CONTENTS

PART I

Item 1. *Business*

Cautionary Statement

The Trustee, its officers or its agents on behalf of the Trustee may, from time to time, make forward-looking statements (other than statements of historical fact). In addition, this Report on Form 10-K may contain forward-looking statements. When used herein, the words anticipates, expects, believes, intends or projects and similar expressions are intended to identify forward-looking statements. To the extent that any forward-looking statements are made, the Trustee is unable to predict future changes in gas prices, gas production levels, economic activity, legislation and regulation, and certain changes in expenses of the Trust. In addition, the Trust s future results of operations and other forward looking statements contained in this item and elsewhere in this report involve a number of risks and uncertainties. As a result of variations in such factors, actual results may differ materially from any forward-looking statements. Some of these factors are described below. The Trustee disclaims any obligations to update forward looking statements and all such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph.

Definitions

As used herein, the following terms have the meanings indicated: Mcf means thousand cubic feet of gas, MMcf means million cubic feet of gas, Bbl means barrel (approximately 42 U.S. gallons), and MBbl means thousand barrels, Btu means British thermal units and MMBtu means million British thermal units.

The following descriptions of the Eastern American Natural Gas Trust (the Trust), the Depositary Units, the Net Profits Interests, the Underlying Properties and the calculation of amounts payable to the Trust, are subject to and qualified in their entirety by the more detailed provisions of the Trust Agreement, the Depositary Agreement, the Conveyances and the Gas Purchase Contract (each as defined below), all of which are incorporated by reference as exhibits to this Form 10-K and available upon request from The Bank of New York (the Trustee). The information contained herein relating to the operations of the Underlying Properties, as well as information upon which the reserve figures and financial information contained herein were derived, was furnished to the Trust by Eastern American Energy Corporation (Eastern American).

DESCRIPTION OF THE TRUST

The Trust was formed under the Delaware Business Trust Act pursuant to a Trust Agreement (the Trust Agreement) among Eastern American, as grantor, Bank of Montreal Trust Company, as Trustee (Trustee), and Wilmington Trust Company, as Delaware Trustee (the Delaware Trustee). Effective May 8, 2000, The Bank of New York acquired the corporate trust business of the Bank of Montreal Trust Company / Harris Trust. Consequently, The Bank of New York serves as Trustee.

The Trust was formed to acquire and hold net profits interests (the Net Profits Interests) created from the working interests owned by Eastern American in 650 producing gas wells and 65 proved development well locations located in West Virginia and Pennsylvania (the Underlying Properties). A portion of the production from the wells burdened by the Net Profits Interests was intended to be eligible for credits (Section 29 Credits) under the Internal Revenue Code of 1986 for production of gas from Devonian shale or tight formations. The Net Profits Interests to be acquired consisted of a royalty interest in 322 wells and a term interest in the remaining wells and locations. Eastern American was obligated to drill and complete, at its expense, 65 development wells (the Development Wells) on the development well locations conveyed to the Trust. Eastern American has fulfilled its obligation with respect to the drilling of the Development Wells (see Note 1 of Financial Statements attached as Annex B). After May 15, 2012 and prior to or on May 15, 2013 (the Liquidation Date), the Trustee is required to sell the remaining royalty interests and liquidate the Trust.

On March 15, 1993, 5,900,000 Depositary Units were issued in a public offering at an initial public offering price of $20.50 per Depositary Unit. Each Depositary Unit consists of beneficial ownership of one unit of beneficial interest (Trust Unit) in the Trust and a $20 face amount beneficial ownership interest in a $1,000 face amount zero coupon United States Treasury obligation (Treasury Obligation) maturing on May 15,

2013. Holders of Depositary

1

Units (Unitholders) may withdraw the Treasury Obligations associated with the Trust Units see Description of Trust Units and Depositary Units . Of the net proceeds from such offering, $27,787,820 was used to purchase $118,000,000 in face amount of Treasury Obligations and $93,162,180 was retained by Eastern American in consideration for the conveyance of the Net Profits Interests to the Trust. The Trust acquired the Net Profits Interests effective as of January 1, 1993.

The Net Profits Interests are passive in nature, and neither the Trustee nor the Delaware Trustee has management control or authority over, nor any responsibility relating to, the operation of the Underlying Properties (defined below) subject to the Net Profits Interests. The Trust Agreement provides, among other things, that: the Trust shall not engage in any business or commercial activity or acquire any asset other than the Net Profits Interests initially conveyed to the Trust; the Trustee may establish a reserve for payment of any liability which is contingent, uncertain in amount or that is not currently due and payable; the Trustee is authorized to borrow funds required to pay liabilities of the Trust, provided that such borrowings are repaid in full prior to further distributions to Unitholders and other holders of Trust Units (together, Trust Unitholders); and the Trustee will make quarterly cash distributions to Trust Unitholders from funds of the Trust.

The Trust is responsible for paying the Trustee s fee and all legal, accounting, engineering and stock exchange fees, printing costs and other administrative expenses incurred by or at the direction of the Trustee. The total fees paid to the Trustee for 2003 were $45,000. The total of all Trustee fees and Trust administrative expenses for 2003 was $536,803. Such costs could fluctuate in the future depending primarily on the expenses the Trust incurs for professional services, particularly legal, accounting and engineering services. In addition to such expenses, in 2003, the Trust paid Eastern American an overhead reimbursement of $296,224. The overhead reimbursement increases by 3.5% per year and is payable quarterly.

THE NET PROFITS INTERESTS

The Conveyances

The Net Profits Interests (NPI) were created from the Underlying Properties and conveyed to the Trust pursuant to two Conveyances - one conveying a royalty interest in specified wells (the Royalty NPI Conveyance) and the other conveying the a term interest in specified wells (the Term NPI Conveyance , and together with the Royalty NPI Conveyance, the Conveyances). Forms of the Conveyances have been incorporated by reference as exhibits to this report.

The Underlying Properties are subject to and burdened by the Net Profits Interests. The interests of Eastern American comprising the Underlying Properties represent, on average, a working interest of approximately 90% and a net revenue interest of approximately 76%. The Conveyances provide that the Trust is only entitled to gas produced from the specific wells identified in the Conveyances and is not entitled to any gas produced from adjacent wells (including adjacent wells subject to the same lease or farmout agreement as the wells subject to the Net Profits Interests). Gas produced from the Underlying Properties which is attributable to the Net Profits Interests is purchased from the Trust by Eastern Marketing Corporation, a wholly-owned subsidiary of Eastern American (Eastern Marketing) pursuant to a gas purchase contract (the Gas Purchase Contract). The volumes attributable to the Net Profits Interests and the purchase price for such gas is calculated for each calendar quarter, and payment for such gas is made to the Trust not later than the 10th day of the third calendar month following the end of each calendar quarter.

The Royalty NPI is not limited in term or amount. Under the Trust Agreement, the Trustee is directed to sell all remaining Royalty NPI after May 15, 2012 and prior to May 15, 2013, and net proceeds from selling such Royalty NPI will be distributed to Unitholders on the first quarterly payment date following the receipt of such proceeds by the Trust. The Term NPI will expire on the earlier of May 15, 2013 or such time as 41,683 MMcf of gas has been produced which is attributable to Eastern American s net revenue interests in the properties burdened by the Term NPI. As of December 31, 2003, 19,548 MMcf of such gas had been produced.

Eastern American can sell the Underlying Properties, subject to and burdened by the Net Profits Interests, without the consent of the Trust or the Unitholders. In limited circumstances, Eastern American also can transfer the Underlying Properties and require the Trust to release the NPI burdening that property, without the consent of the Trust or Unitholders, subject to payment to the Trust of the fair value of the interest released. In addition, any abandonment of a well included in the Underlying Properties or the Development Wells will extinguish that portion of the Net Profits Interests that relate to such well. See Sale and Abandonment of Underlying Properties; Sale of Royalty NPI.

Calculation of Net Proceeds

The definitions, formulas, accounting procedures and other terms governing the computation of Net Proceeds are detailed and extensive, and reference is made to both the Royalty NPI Conveyance and the Term NPI Conveyance for a more detailed discussion of the computation thereof.

The Conveyances and the Gas Purchase Contract entitle the Trust to receive an amount of cash for each calendar quarter equal to the Net Proceeds for such quarter. Net Proceeds for any calendar quarter generally means an amount of cash equal to (a) 90% of a volume of gas equal to (i) the volume of gas produced during such quarter attributable to the Underlying Properties less (ii) a volume of gas equal to Chargeable Costs, as defined below, for such quarter, multiplied by (b) the applicable price for such quarter under the Gas Purchase Contract. If, for any reason, the Gas Purchase Contract terminates prior to the Liquidation Date, Net Proceeds will mean an amount of cash equal to (a) 90% of a volume of gas equal to (i) the volume of gas produced during such quarter attributable to the Underlying Properties less (ii) a volume of gas equal to Chargeable Costs for such quarter, multiplied by (b) the applicable price for such quarter determined in accordance with the Conveyances. Pursuant to the Conveyances, the Trust is not entitled to receive any natural gas liquids produced from the Underlying Properties or any proceeds relating thereto.

Chargeable Costs is that volume of gas which equates in value, determined by reference to the relevant sales price under the Gas Purchase Contract or the Conveyances, as applicable, to the sum of the Operating Cost Charge , Capital Costs and Taxes (as defined in the Conveyances). The Operating Cost Charge for 2003 was $510,032, for 2002 was $501,738 and for 2001 was $513,107. In 2004 and subsequent years, the Operating Cost Charge will increase based on increases in the index of average weekly earnings of Crude Petroleum and Gas Production Workers (published by the United States Department of Labor, Bureau of Labor Statistics), but not more than five percent (5%) per year and will not decrease even if the index decreases. The Operating Cost Charge will be reduced for each well that is sold (free of the Net Profits Interests) or plugged and abandoned. Capital Costs are defined as Eastern American s working interest share of capital costs for operations on the Underlying Properties having a useful life of at least three years, and excluding any capital costs incurred in drilling the Development Wells. Taxes refer to ad valorem taxes, production and severance taxes, and other taxes imposed on Eastern American s or the Trust s interests in the Underlying Properties, or production therefrom.

Although the Trust bears the full economic burden of Chargeable Costs, it does so indirectly in the calculation of Net Proceeds and the Trust is not directly liable for any share of the costs, risks, and liabilities associated with the ownership or operation of the Underlying Properties. If the Trust ever receives payments in excess of the Net Proceeds or other amounts it was not entitled to receive, the Trust will not be required to refund the money, but Eastern American may recover the amount of such overpayments from future distributions in accordance with the Conveyances.

The Conveyances require Eastern American to maintain books, records, and accounts sufficient to calculate the volumes of gas and the share of Net Proceeds payable to the Trust. Eastern American provides to the Trust quarterly and annual statements of applicable production, revenues, and costs necessary for the Trust to prepare quarterly and annual financial statements with respect to the Net Profits Interests and the Underlying Properties. The financial statements of the Trust are audited annually at the Trust s expense.

Gas Purchase Contract

Gas production attributable to the Net Profits Interests is purchased from the Trust by Eastern Marketing, a wholly owned subsidiary of Eastern American, pursuant to the Gas Purchase Contract which effectively commenced as of January 1, 1993 and expires upon the termination of the Trust.

Under the Gas Purchase Contract, through the Primary Term ending December 31, 1999, Eastern Marketing purchased gas from the Trust at an Index Price calculated based on a Fixed Price component (escalating at 5% a year and carrying a 66-2/3% weighting) and a Variable Price component (varying with the Henry Hub market price as described below and carrying a 33-1/3% weighting), subject to a minimum Floor Price (as defined in the Gas Purchase Contract). Since January 1, 2000, and the end of the Primary Term, Eastern Marketing has purchased gas from the Trust at an Index Price composed only of the Variable Price component, and not subject to any minimum Floor Price. The Variable Price for any quarter is equal to the Henry Hub Average Spot Price (as defined) per MMBtu plus $0.30 per MMBtu, multiplied by 110% to effect a fixed adjustment for Btu content. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter equal to the price obtained with respect to each of the three months in such quarter, in the manner specified below, and then taking the average of the prices determined for each of such three months. The price determined for any month of such quarter is equal to the average of (i) the final settlement prices per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in *The Wall Street Journal,* for such contracts which expired in each of the five months prior to such month, (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in *The Wall Street Journal,* for such contracts which expire during such month and (iii) the closing settlement prices per MMBtu of Henry Hub Gas Futures Contracts determined as of the contract settlement date for such month, as reported in *The Wall Street Journal,* for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub, which is traded on the New York Mercantile Exchange.

The purchase price paid to the Trust pursuant to the Gas Purchase Contract is a wellhead price and title to the gas purchased pursuant to the Gas Purchase Contract passes to Eastern Marketing at the point of delivery. Payments to the Trust for gas purchased pursuant to the Gas Purchase Contract are made by Eastern Marketing on or before the tenth day of the third calendar month following the end of each calendar quarter.

The Trust Agreement provides that the Trustee may not agree to any amendment to the Gas Purchase Contract which would materially and adversely affect the revenues to the Trust without the approval of the holders of a majority of the outstanding Trust Units. The Trust Agreement also provides that the Gas Purchase Contract may not be terminated by the Trust without the approval of the holders of a majority of the outstanding Trust Units. The Gas Purchase Contract and the Trust Agreement have been filed as exhibits to this Form 10-K by reference to materials previously filed with the Securities and Exchange Commission. See Part IV, Item 15, Exhibits, Financial Statement Schedules, and Reports on Form 8-K . The foregoing summary of the principal provisions of the Gas Purchase Contract, and certain provisions of the Trust Agreement, is qualified in its entirety by reference to the terms of such agreements as set forth in such exhibits.

Eastern Marketing s rights and obligations under the Gas Purchase Contract are assignable under circumstances where the assignee unconditionally assumes Eastern Marketing s obligations under the Gas Purchase Contract, and then, only if such assignee (or assignee s parent corporation if such parent guarantees the assignee s obligations) has a rating assigned to its unsecured long-term debt by Moody s Investor Service of at least Baa+ and by Standard & Poor s Corporation of at least BBB-. Under such circumstances, Eastern Marketing and Eastern American would be released from their obligations under the Gas Purchase Contract.

Performance Support for Gas Purchase Contract

Gas production attributable to the Net Profits Interests will be purchased by Eastern Marketing pursuant to the Gas Purchase Contract, which expires upon the Liquidation Date of the Trust. Eastern American has agreed to make payment under a standby performance agreement to the extent such payments are not made by Eastern Marketing under the Gas Purchase Contract.

Distributions and Income Computations

The Trustee determines for each quarter the amount of cash available for distribution to holders of Depositary Units and the Trust Units evidenced thereby. Such amount (the Quarterly Distribution Amount) is equal to the excess, if any, of (i) the cash that the Trust receives on or before the tenth day of the third month after the end of each calendar quarter ending before the Trust is dissolved and that is attributable to production from the Net Profits Interest held by the Trust during that calendar quarter, plus, with certain exceptions, any other cash receipts of the Trust during such quarter, over (ii) the liabilities of the Trust paid during such quarter, subject to adjustments for changes made by the Trustee during such quarter in any cash reserves established for the payment of contingent or future obligations of the Trust. Quarterly Distribution Amounts for each of the quarters in 2003 were $0.38, $0.52, $0.51, and $0.41 respectively. Based on the payment procedures relating to the Net Profits Interests, cash received by the Trustee in a particular quarter from the Net Profits Interests reflects actual gas production for a portion of such quarter and a production estimate for the remainder of such quarter, such estimate to be adjusted to actual production in the following quarter. The Quarterly Distribution Amount for each quarter is payable to Unitholders of record on the last day of the second month 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 (Quarterly Record Date). It is expected that the Trustee will continue to be able to distribute

4

cash on or before the 15th day (or the next succeeding business day following such day if such day is not a business day) of the third month following the end of each calendar quarter to each person who was a Unitholder of record on the Quarterly Record Date, together with interest earned on such Quarterly Distribution Amount from the date of receipt thereof by the Trustee to the payment date.

The net taxable income of the Trust for each calendar quarter is reported by the Trustee for tax purposes as belonging to the holders of record to whom the Quarterly Distribution Amount was or will be distributed. Assuming that the Trust will be classified for tax purposes as a grantor trust, the net taxable income will be realized by the holders for tax purposes in the calendar quarter received by the Trustee, rather than in the quarter distributed by the Trustee. Thus, a Unitholder s taxable income for a taxable year may differ from the cash the Unitholder receives during that year. In addition, taxable income of a holder will differ from the Quarterly Distribution Amount because the Treasury Obligations will be treated as generating interest income for tax purposes. There may also be minor variances because of the possibility that, for example, a reserve will be established in one quarter that will not give rise to a tax deduction until a subsequent quarter, an expenditure paid for in one quarter will have to be amortized for tax purposes over several quarters, etc. See Federal Income Tax Matters.

Each holder of Depositary Units (including the underlying Trust Units) of record as of the record date for the final quarter of the Trust s existence will be entitled to receive a liquidating distribution equal to a pro rata portion of the net proceeds from the sale of the Royalty NPI (to the extent not previously distributed) and a pro rata portion of the proceeds from the matured Treasury Obligations.

Sale and Abandonment of Underlying Properties; Sale of Royalty NPI

Eastern American and any transferees have the right to abandon any well or working interest included in 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 Eastern American and the Trust in determining whether a well is capable of producing in paying quantities, Eastern American is required under the Conveyances to make any such determination as would a reasonably prudent operator in the Appalachian Basin if it were acting with respect to its own properties, disregarding (i) the existence of the Net Profits Interests as a burden on such property and (ii) the direct or indirect effect, financial or otherwise, on Eastern American or any of its affiliates that may result from the performance by Eastern Marketing of its obligations under the Gas Purchase Contract.

Eastern American has the right, pursuant to the Conveyances, to sell all or any portion of the Underlying Properties without restrictions; however, the purchaser of any of the Underlying Properties will acquire such Underlying Properties subject to the Net Profits Interests relating thereto (except in certain circumstances described below where the Trust may be required to release the Net Profits Interests, subject to its receipt of the fair value thereof). Any such purchaser will be subject to the same standards of conduct with respect to development, operation and abandonment of such Underlying Properties as set forth in the preceding paragraph.

Eastern American may sell the Underlying Properties, subject to and burdened by the Net Profits Interests, without the consent of the Trust or the Unitholders. In addition, prior to January 1, 2003, Eastern American could, without the consent of the Trust or the Unitholders, require the Trust to release Net Profits Interests associated with any well accounting for 0.25% or less of the total production from the Underlying Properties in the prior 12 months, provided that, such releases cannot exceed five (5) wells during any 12 month period. In addition until January 1, 2010, such releases cannot exceed an aggregate value to the Trust of $500,000 during any 12 month period. Sales subsequent to that time may be made without regard to dollar limitations. These releases will be made only in connection with a sale by Eastern American of the Underlying Properties and are conditioned upon the Trust receiving an amount equal to the fair value to the Trust of such Net Profits Interests (taking into account the existence of the Gas Purchase Contract with respect to the gas attributable to the Net Profits Interests to be released). Any proceeds paid to the Trust are distributable to Unitholders for the quarter in which they are received.

The Trustee is required to sell all of the Royalty NPI after May 15, 2012 and prior to the Liquidation Date. The proceeds of such sale, together with the matured face amount of the Treasury Obligations, will be distributed to Unitholders on or prior to the Liquidation Date. Under the Trust Agreement, Eastern American has a right of first refusal to purchase any of the Royalty NPI at the fair value to the Trust, or if applicable the offered third-party price, prior to the Liquidation Date.

THE UNDERLYING PROPERTIES

General

The Underlying Properties are comprised of Eastern American s working interests in certain properties located in the Appalachian Basin states of West Virginia and Pennsylvania. As of December 31, 2003, such properties consisted of 677 producing gas wells. The working interests of Eastern American comprising the Underlying Properties are held under leases and farmout agreements with third parties. Such working interests are subject to landowner s royalties (typically 12-1/2%) and may be subject to additional royalties or other obligations burdening the working interests. Such royalties do not bear lease operating expenses, but reduce the revenue interests attributable to the Underlying Properties. Eastern American s interests comprising the Underlying Properties represent, on average, a working interest of approximately 90% and a net revenue interest of approximately 76%. As of December 31, 2003, proved developed reserves attributable to the Net Profits Interests (reflecting quantities of gas free of future costs and expenses based on estimated prices) were approximately 22,710 MMcf. (See Reserves).

The Appalachian Basin is a mature producing region with well known geologic characteristics. Substantially all of the wells comprising the Underlying Properties are relatively shallow, ranging from 2,500 to 5,500 feet, and many are completed to multiple producing zones. In general, the wells to which the Underlying Properties relate are proved producing properties with stable production profiles and generally long-lived production, often with total projected economic lives in excess of 25 years. Once drilled and completed, ongoing operating and maintenance requirements are low and only minimal, if any, capital expenditures are typically required.

The Underlying Properties initially included 65 specified development well locations for the drilling of the Development Wells by Eastern American. Eastern American was obligated to bear the costs of drilling and completing the Development Wells. Eastern American has fulfilled its obligation with respect to the drilling of the Development Wells. (see Note 1 of Financial Statements attached as Annex B)

Eastern American acquired its interests in the Underlying Properties under or through (i) oil and gas leases granted by the mineral owner directly to Eastern American, (ii) assignments of oil and gas leases by the lessee who originally obtained the leases from the mineral owner, (iii) farmout agreements that grant Eastern American the right to earn interests in the properties covered by such agreements by drilling wells and (iv) the acquisitions of oil and gas interests by Eastern American.

Production from the wells to which the Underlying Properties relate is typically subject to, in one degree or another, (i) landowner royalties and other burdens and obligations retained under oil and gas leases, (ii) overriding royalty interests and (iii) interests of other working interest owners in the wells. The royalty and overriding interests entitle the holders thereof to a certain percentage of the oil and gas produced from the wells or the proceeds therefrom and are generally delivered free of all expenses of production but may be subject to post-production costs, such as production or gathering taxes, costs to treat the gas to render it marketable, and certain transportation or gathering costs. Royalty interests are usually reserved by the lessor under an oil and gas lease. Overriding royalty interests are carved out of a lessee s share of production under an oil and gas lease and are generally reserved by a predecessor in title or reserved under farmout agreements.

A farmout agreement is typically an agreement under which a lessee under an oil and gas lease (the Farmor) grants to another party the right to drill wells on the tract covered by such lease and to earn certain acreage for drilling such wells. In the Appalachian Basin, the Farmor generally receives a well location fee and reserves an overriding royalty interest in the wells which typically ranges from 3.25% to 6.25%. Farmout agreements typically provide that wells must be drilled and completed as a condition to a transfer by the Farmor of the interest in the underlying lease.

Reserves

Proved Reserves of Underlying Properties and Net Profits Interests. The following table sets forth, as of December 31, 2003, certain estimated proved reserves, estimated future net revenues and the discounted present value thereof attributable to the Underlying Properties, the Royalty NPI and the Term NPI, in each case derived from a report of oil and gas reserves attributable to the Trust as of December 31, 2003 prepared by Ryder Scott Company (the Reserve Report). Proved reserve quantities attributable to the Net Profits Interests are calculated by subtracting an amount of gas sufficient, if sold at the prices used in preparing the reserve estimates, to pay the future estimated costs and expenses

6

deducted in the calculation of Net Proceeds. Accordingly, the reserves attributable to the Net Profits Interests reflect quantities of gas that are free of future costs or expenses if the price and cost assumptions set forth in the Reserve Report occur. A decrease in the price assumption, or an increase in the cost assumption used in the Reserve Report would reduce the estimates of proved reserves, future net revenues and discounted future net revenues, set forth herein and in the Reserve Report. The Term NPI excludes production beyond the earlier of May 15, 2013 or such time as 41,683 MMcf of gas has been produced which is attributable to Eastern American s net revenue interests in the properties burdened by the Term NPI. The discounted present value of estimated future net revenues was determined using a discount rate of 10% in accordance with existing securities law requirements. A copy of the Reserve Report is included as Exhibit A hereto.

	Proved Gas Reserves (MMcf)				
	Developed	**Undeveloped**	**Total**	**Estimated Future Net Revenues(2)**	**Discounted Estimated Future Net Revenues(2)**
				(Dollars in thousands)	
Underlying Properties(1)	37,311	0	37,311	$ 173,665	$ 71,622
Net Profits Interests:					
Royalty NPI	14,142	0	14,142	$ 64,646	$ 27,357
Term NPI	8,568	0	8,568	42,743	29,092
Total	22,710	0	22,710	$ 107,389	$ 56,449

(1) Reserve volumes and estimated future net revenues for Underlying Properties reflect volumes and revenues distributable to Eastern American s entire net revenue interest with respect to the Underlying Properties.

(2) The effects of depreciation, depletion and federal income tax have not been taken into account in estimating future net revenues. Estimated future net revenues and discounted estimated future net revenues are not intended, and should not be interpreted, as representing the fair market value for the estimated reserves.

The value of the Depositary Units and the Trust Units evidenced thereby are substantially dependent upon the proved reserves and production levels attributable to the Net Profits Interests. There are many uncertainties inherent in estimating quantities and values of proved reserves and in projecting future rates of production and the timing of development expenditures, if any. The reserve data set forth herein, although prepared by independent engineers in a manner customary in the industry, are estimates only, and actual quantities and values of gas are likely to differ from the estimated amounts set forth herein. In addition, the discounted present values shown herein were prepared using guidelines established by the Securities and Exchange Commission (the Commission) and Financial Accounting Standards Board for disclosure of reserves and should not be considered representative of the market value of such reserves or the Depositary Units or the Trust Units evidenced thereby. A market value determination would include many additional factors.

COMPETITION AND MARKETS

All of the production attributable to the Net Profits Interest is sold to Eastern Marketing pursuant to the Gas Purchase Contract, under which, since January 1, 2000, all such production is purchased at a purchase price per Mcf equal to the Index Price, composed only of the Variable Price. See The Net Profits Interests - Gas Purchase Contract.

REGULATION OF NATURAL GAS

The natural gas industry has historically been highly regulated by state and federal authorities. In the past, concerns about perceived pipeline monopolies and other factors caused Congress to impose economic regulation on both pipelines and producers. Federal agencies regulated tariffs and conditions of service offered by interstate pipelines, and set maximum prices on the wellhead price of natural gas sold into interstate commerce. States, and even local governments, also regulated retail sales of natural gas by local utilities. Government agencies also set production rates to avoid waste and imposed environmental and safety regulations. At present, it appears that Federal regulation of wellhead natural gas prices has ended. However there can be no assurance that price controls or other similar economic regulations may not be reimposed in the future.

Drilling and production of natural gas are heavily regulated in Pennsylvania and West Virginia, as in most states. A well cannot be drilled without a permit, and operations must be conducted in compliance with environmental, safety and conservation laws and regulations. In contrast to many other states which have substantial oil and gas production activity, the spacing of shallow wells (such as the wells subject to the Net Profits Interests) is not regulated by any state statute or regulatory agency in either West Virginia or Pennsylvania. Without spacing requirements specified by state statute or regulation, drainage of reserves from a property may occur from wells located in close proximity to such property.

HEALTH, SAFETY, AND ENVIRONMENTAL REGULATION

General. Activities on the Underlying Properties are subject to existing Federal, state and local laws and regulations governing health, safety, environmental quality and pollution control. It is anticipated that, absent the occurrence of an extraordinary event, compliance with existing Federal, state and local laws, rules and regulations regulating health, safety, the discharge of materials into the environment or otherwise relating to the protection of the environment will not have a material adverse effect upon the Trust. It cannot be predicted what effect additional regulation or legislation, enforcement policies thereunder, and claims for damages to property, employees, other persons and the environment resulting from operations on the Underlying Properties could have on the Trust. However, pursuant to the terms of the Conveyances, any costs or expenses incurred in connection with environmental liabilities of Eastern American arising out of or related to activities occurring on or in, or conditions existing on or under, the Underlying Properties before the effective date of the Conveyances will be borne by Eastern American and will not be deducted in calculating Net Proceeds attributable to the Net Profits Interests. Additionally, because Unitholders will have limited liability in accordance with the Trust Agreement and Delaware law, Unitholders should be shielded from direct liability for any environmental liabilities. See Description of Trust Units and Depositary Units Liability of Unitholders. However, costs and expenses incurred by Eastern American for certain Capital Costs associated with environmental liabilities arising after the effective date of the Conveyances would reduce Net Proceeds, and would therefore be borne, in part, by the Unitholders. The following subtopics discuss some of the principal forms of health, safety, and environmental regulation to which the Underlying Properties and operations thereon are subject. The costs of complying with these regulatory requirements may burden the Net Profits Interests to the extent they arise out of or are related to activities occurring on or in, or conditions existing on or under, the Underlying Properties after the effective date of the Conveyances.

Solid and Hazardous Waste. The Underlying Properties include numerous properties that have produced gas for a number of years but in which Eastern American has held an interest for a relatively short period of time prior to the effective date of the Conveyances. Although, to Eastern American s knowledge, prior operators utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other solid or hazardous wastes may have been disposed of or released on or under the Underlying Properties. Federal, state and local laws applicable to gas-related wastes have become increasingly more stringent. Under current laws, Eastern American or the operator of the Underlying Properties could be required to remove or remediate previously disposed wastes or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

The operations of the Underlying Properties may generate wastes that are subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The Environmental Protection Agency (the EPA) has limited the disposal options for certain hazardous wastes and may adopt more stringent disposal standards for nonhazardous wastes.

Superfund. The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the superfund law, imposes liability, regardless of fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the current or previous owner and operator of a site and companies that disposed or arranged for the disposal of, the hazardous substance found at a site. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to the public health or the environment and to seek recovery from such responsible classes of persons of the costs of such action. In the course of their operations, the operators of the Underlying Properties have generated and will generate wastes that may fall within CERCLA s definition of hazardous substances . Eastern

American or the previous operator of the Underlying Properties may be responsible under CERCLA for all or part of the costs to clean up sites at which such substances have been disposed.

Air Emissions. The operations of the Underlying Properties are subject to Federal, state and local regulations concerning the control of emissions from sources of air contaminants. Administrative enforcement actions for failure to comply strictly with air regulations or permits are generally resolved by payment of a monetary penalty and correction of any identified deficiencies. Regulatory agencies could require the operators to forego or modify construction or operation of certain air emission sources.

OSHA. The operations of the Underlying Properties are subject to the requirements of the Federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and similar state statutes require that information be organized and maintained about hazardous materials used or produced in the operations. Certain of this information must be provided to employees, state and local government authorities and citizens.

DESCRIPTION OF TRUST UNITS AND DEPOSITARY UNITS

The following information is subject to the detailed provisions of the Deposit Agreement entered into by Eastern American, the Trustee, and Bank of Montreal Trust Company (The Bank of New York after May 8, 2000), as Depositary (the Depositary) and all holders from time to time of Depositary Units (the Deposit Agreement), which is incorporated by reference as an exhibit to this Form 10-K and is available upon request.

The functions of the Depositary under the Deposit Agreement are custodial and ministerial in nature and for the benefit of Unitholders. The Deposit Agreement and the issuance of Depositary Units thereunder provide Unitholders an administratively convenient form of holding an investment in the Trust and a Treasury Obligation. Each Depositary Unit is evidenced by a certificate, which is issued by the Depositary and transferable only in denominations of 50 Depositary Units or an integral multiple thereof. Accordingly, each holder of 50 Depositary Units owns a beneficial interest in 50 Trust Units and the entire beneficial interest in a discrete Treasury Obligation in a face amount of $1,000, or $20 per Depositary Unit.

The deposited Trust Units and Treasury Obligations are held solely for the benefit of the Unitholders and do not constitute assets of the Depositary or the Trust. The Depositary has no power to assign, transfer, pledge or otherwise dispose of any of the Trust Units or Treasury Obligations, except in the limited instances provided in the Deposit Agreement.

Generally, the holders of Depositary Units are entitled to participate in distributions with respect to the Trust Units, the Treasury Obligations and to the liquidation of the remaining assets of the Trust.

Withdrawal of Trust Units and Restrictions on Transfer

Upon presentation of Depositary Units in denominations of 50 or integral multiples thereof for withdrawal of the Trust Units and discrete Treasury Obligations evidenced thereby in accordance with the Deposit Agreement, the Unitholder will receive an uncertificated direct interest in Trust Units. These withdrawn Trust Units will be evidenced on the books of the Trustee by a transfer of such Trust Units from the name of the Depositary to the name of the withdrawing Unitholder. Holders of withdrawn Trust Units will be entitled to receive Trust distributions and periodic Trust information (including tax information) directly from the Trustee. Moreover, holders of Trust Units will be entitled to each of the rights accorded Unitholders under the Trust Agreement, including voting and liquidation rights, as elsewhere described herein, except that withdrawn Trust Units are not freely transferable as described below.

Pursuant to the Trust Agreement and the transfer application for transfer of the Trust Units, withdrawn Trust Units are not transferable except by operation of law. A holder of withdrawn Trust Units may, however, transfer such Trust Units in denominations of 50 (or integral multiples thereof) to the Depositary for redeposit, together with Treasury Obligations in the face amount equal to $1,000 for each 50 Trust Units redeposited, in exchange for Depositary Units. Such redeposit may be effected by delivering written notice of such transfer jointly to the Depositary and the Trustee together with proper documentation necessary to transfer the requisite Treasury Obligations into the name of the Depositary.

Distributions and Income Computations

The Trustee determines for each quarter the Quarterly Distribution Amount available for distribution to holders of Depositary Units and the Trust Units evidenced thereby. The Quarterly Distribution Amount is equal to the excess, if any, (i) the cash that the Trust receives on or before the tenth day of the third month after the end of each calendar quarter ending before the Trust is dissolved and that is attributable to production from the Net Profits Interest held by the Trust during that calendar quarter, plus, with certain exceptions, any other cash receipts of the Trust during such quarter, over (ii) the liabilities for the Trust paid during such quarter, subject to adjustments for changes made by the Trustee during such quarter in any cash reserves established for the payment of contingent or future obligations of the Trust. Based on the payment procedures relating to the Net Profits Interests, cash received by the Trustee in a particular quarter from the Net Profits Interests reflects actual gas production for a portion of such quarter and a production estimate for the remainder of such quarter, such estimate to be adjusted to actual production in the following quarter. The Quarterly Distribution Amount for each quarter is payable to Unitholders of record on the Quarterly Record Date, which is the last day of the second month 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 Trustee generally is able to distribute cash on or before the 15th day (or the next succeeding business day following such day if such day is not a business day) of the third month following the end of each calendar quarter to each person who was a Unitholder of record on the Quarterly Record Date, together with interest earned on such Quarterly Distribution Amount from the date of receipt thereof by the Trustee to the payment date.

The net taxable income of the Trust for each calendar quarter is reported by the Trustee for tax purposes as belonging to the holders of record to whom the Quarterly Distribution Amount was or will be distributed. Assuming that the Trust will be classified for tax purposes as a grantor trust, the net taxable income will be realized by the holders for tax purposes in the calendar quarter received by the Trustee, rather than in the quarter distributed by the Trustee. Taxable income of a holder may differ from the Quarterly Distribution Amount because the Treasury Obligations will be treated as generating interest income for tax purposes. There may also be minor variances because of the possibility that, for example, a reserve will be established in one quarter that will not give rise to a tax deduction until a subsequent quarter, an expenditure paid for in one quarter will have to be amortized for tax purposes over several quarters. See Federal Income Tax Matters .

Each holder of Depositary Units (including the underlying Trust Units) of record as of the record date for the final quarter of the Trust s existence will be entitled to receive a liquidating distribution equal to a pro rata portion of the net proceeds from the sale of the Royalty NPI (to the extent not previously distributed) and a pro rata portion of the proceeds from the matured Treasury Obligations.

Possible Divestiture of Depositary Units and Trust Units

The Trust Agreement imposes no restrictions based on nationality or other status of holders of Trust Units. However, the Trust Agreement and the Deposit Agreement provide that in the event of certain judicial or administrative proceedings seeking the cancellation or forfeiture of any property in which the Trust has an interest because of the nationality, citizenship, or any other status, of any one or more holders of Trust Units including holders of Depositary Units, the Trustee will give written notice thereof to each holder whose nationality, citizenship or other status is an issue in the proceeding, which notice will constitute a demand that such holder dispose of his Depositary Units or withdrawn Trust Units within 30 days. If any holder fails to dispose of his Depositary Units or withdrawn Trust Units in accordance with such notice, cash distributions on such units are subject to suspension. In the event a holder fails to dispose of Depositary Units in accordance with such notice, the Depositary may cancel such holder s Depositary Units and reissue them in the name of the Trustee, whereupon the Trustee will use its reasonable efforts to sell the Depositary Units and remit the net sale proceeds to such holder. In the case of Trust Units withdrawn from deposit with the Depositary, the Trustee shall redeem such Trust Units not divested in accordance with such notice, for a cash price equal to the then-current market price of the Depositary Units less the then-current over-the-counter bid price of the related, withdrawn Treasury Obligations. The redemption price will be paid out in quarterly installments limited to the amount that otherwise would have been distributed in respect of such redeemed Trust Units.

10

Liability of Unitholders

Consistent with Delaware law, the Trust Agreement provides that the Unitholders will have the same limitation on liability as is accorded under the laws of such state to stockholders of a corporation for profit. No assurance can be given, however, that a court would give effect to such limitation.

Liquidation of the Trust

The Trust will be liquidated and the Royalty NPI will be sold prior to the Liquidation Date. Unitholders of record as of the record date for the final quarter of the Trust s existence will be entitled to receive a terminating distribution with respect to each Depositary Unit equal to a pro rata portion of the net proceeds from the sale of the Royalty NPI (to the extent not previously distributed) and a pro rata portion of the proceeds from the matured Treasury Obligations. Under the Trust Agreement, Eastern American has a right of first refusal to purchase the Royalty NPI at fair market value, or if applicable the offered third-party price, prior to the Liquidation Date.

FEDERAL INCOME TAX MATTERS

This section is a summary of Federal income tax matters of general application which addresses the material tax consequences of the ownership and sale of Depositary Units. This section provides a generalized summary of certain federal income tax matters of general application relating to ownership and sale of Depositary units by individuals who are citizens or residents of the United States. Accordingly, the following discussion has only limited application to domestic corporations and persons subject to specialized Federal income tax treatment, such as tax-exempt entities (including IRAs), regulated investment companies and insurance companies. The following discussion also does not address tax consequences to foreign persons. It is impractical to comment on all aspects of Federal laws that may affect the tax consequences of the transactions contemplated hereby and of an investment in Depositary Units as they relate to the particular circumstances of every prospective Unitholder. Each Unitholder should consult his own tax advisor with respect to his particular circumstances including, his alternative minimum tax circumstances.

This summary is based on current provisions of the Internal Revenue Code of 1986, as amended (the Code), existing and proposed regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may or may not be retroactively applied. Some of the applicable provisions of the Code have not been interpreted by the courts or the Internal Revenue Service (IRS).

At the issuance of the Depositary Units, Eastern American obtained an opinion of counsel for the benefit of the Trust, based on certain representations and subject to certain qualifications, that, for Federal income tax purposes, (a) the Trust will be taxed as a grantor trust and not as an association taxable as a corporation, (b) the Term NPI will be taxed as a production payment, (c) the income from the Royalty NPI will be royalty income subject to the allowance for depletion, and (d) a Unitholder will be eligible to claim Section 29 Credits with respect to certain sales of gas production attributable to the Royalty NPI. The Trustee has reported the operations of the Trust consistent with these opinions.

No ruling has been or will be requested from the IRS with respect to any matter affecting the Trust or Unitholders, and thus no assurance can be provided that the statements set forth herein (which do not bind the IRS or the courts) will not be challenged by the IRS or will be sustained by a court if so challenged.

Reports

Unitholders of record are provided informational tax packages in order to permit computation of their taxable income from ownership of Depositary Units.

Treatment of Depositary Units

Purchasers of Depositary Units are treated, for Federal income tax purposes, as purchasing directly an interest in the Treasury Obligations and a Trust Unit. Purchasers are therefore required to allocate the purchase price of their Depositary Unit between the interest in the Treasury Obligations and the Trust Unit in the proportion that the fair market value of each bears to the fair market value of the Depositary Unit. Information regarding purchase price allocations is furnished to Unitholders by the Trustee.

Classification and Taxation of the Trust

For federal income tax purposes, the Trust has been treated and expects to continue to be treated not as an association taxable as a corporation, but as a grantor trust that is not subject to Federal income tax as an entity separate from its beneficial owners. For tax purposes, Unitholders are considered to own and receive the Trust s assets and income as though no trust were in existence. The Trust files an information return, reporting all items of income, credit or deduction which must be included in the tax returns of the Unitholders. If the Trust were determined not to be a grantor trust, it is expected that it would be treated either as a partnership subject to the publicly traded partnership rules under the Code or as an association taxable as a corporation. If the Trust were treated as a publicly traded partnership, it is believed that the Trust s various items of income and deduction would still be taxable to the Unitholders on a current, flow-through basis as partners of a partnership and not to the Trust as an association taxable as a corporation. If the Trust were determined to be an association taxable as a corporation, it would be treated as a separate entity subject to corporate tax on its taxable income, Unitholders would be treated as shareholders, and distributions to Unitholders from the Trust would be treated as nondeductible corporate distributions. Such distributions would be taxable to a Unitholder, first, as dividends to the extent of the Unitholder s pro rata share of the Trust s earnings and profits, then as a tax-free return of capital to the extent of his basis in his Trust Units, and finally as capital gain to the extent of any excess.

Direct Taxation of Unitholders

Assuming that the Trust is treated as a grantor trust for Federal income tax purposes, and Unitholders are treated for Federal income tax purposes as owning a direct interest in the Treasury Obligations and the assets of the Trust, each Unitholder is taxed directly on his pro rata share of the income attributable to the Treasury Obligations and the assets of the Trust and is entitled to claim his pro rata share of the deductions and credits attributable to the Trust (subject to certain limitations discussed below). Income, credits and expenses attributable to the assets of the Trust and the Treasury Obligations are taken into account by Unitholders consistent with their method of accounting and without regard to the taxable year or accounting method employed by the Trust.

The Trust makes quarterly distributions to Unitholders of record on each Quarterly Record Date. The terms of the Trust Agreement, as described below, seek to assure to the extent practicable that taxable income attributable to such distributions will be reported by the Unitholder who receives such distribution, assuming that he is the owner of record on the Quarterly Record Date. In certain circumstances, however, a Unitholder will not receive the distribution attributable to such income. For example, if the Trustee establishes a reserve or borrows money to satisfy liabilities of the Trust, income associated with the cash used to establish that reserve or to repay that loan must be reported by the Unitholder, even though that cash is not distributed to him. In addition, Unitholders must recognize certain interest income attributable to the Treasury Obligations with respect to which no current cash distributions will be made.

The Trust allocates income, deductions and credits to Unitholders based on record ownership at Quarterly Record Dates. The IRS could require income and deductions of the Trust to be determined and allocated daily or require some method of daily proration, which could result in an increase in the administrative expenses of the Trust.

Under current market conditions, it is anticipated that total distributable cash will exceed taxable income through 2004. After 2004, taxable income is anticipated to exceed distributable cash, and the amount of such excess could be significant. Such estimates are based on numerous assumptions as to the allocation of a Unitholder s purchase price and the amount and treatment of operating costs, development costs, Trust administrative expenses, production estimates and depletion. No assurance can be given that the estimates will prove to be correct, and the actual relationship between distributable cash and taxable income could be materially higher or lower.

Treatment of Trust Units

On the assumption that the Trust is a grantor trust for Federal income tax purposes, each Unitholder is treated as purchasing directly an interest in the Net Profits Interests. Purchasers of Depositary Units must allocate the portion of their total purchase price allocated to the Trust Unit between the Royalty NPI and the Term NPI in the proportion that the fair market value of each bears to the total fair market value of both. Information regarding purchase price allocations is furnished to Unitholders by the Trustee.

Interest Income

The Term NPI will be treated as a production payment under Section 636(a) of the Code. Thus, Unitholders are treated as making a mortgage loan on the Underlying Properties of the Term NPI to Eastern American in an amount equal to the amount of the purchase price of each Depositary Unit allocated to the Term NPI. Because it is treated as a debt instrument for tax purposes, the Term NPI will be subject to the original issue discount income (OID) rules of the Code which generally require the periodic inclusion of the original issue discount in income of the purchaser of a debt instrument. The Code also authorizes the IRS to prescribe regulations modifying the statutory provisions where, by reason of contingent payments such as those provided for by the Term NPI, the tax treatment provided under the Code provisions does not carry out the purposes of such provisions.

The IRS has issued a series of proposed and final regulations dealing with debt instruments which call for contingent payments. The initial set of proposed regulations dealing with this topic were issued on April 8, 1986, and modified on February 26, 1991 (the Old Proposed Regulations). A second set of proposed contingent payment regulations were issued on January 19, 1993, but were withdrawn prior to publication in the Federal Register. On December 15, 1994, the IRS replaced the Old Proposed Regulations by issuing a third set of proposed regulations addressing debt obligations that provide for contingent payments (the New Proposed Regulations). The New Proposed Regulations were proposed to be effective for debt obligations issued on or after the date that is sixty days following the promulgation of the New Proposed Regulations in final form. In this regard, the New Proposed Regulations have been adopted in final form (the Final Regulations), though effective only for debt instruments issued after August 12, 1996. Thus, by their terms, the New Proposed Regulations and the Final Regulations do not apply to the Term NPI. However, the Preamble to the Final Regulations provides that for debt instruments issued prior to the effective date of the Final Regulations, a taxpayer may use any reasonable method to account for such debt instruments, including a method that would have been permitted under the proposed regulations when the debt instrument was issued.

The Trustee understands that, in accordance with the foregoing, Eastern American, as obligor under the Term NPI, intends to continue to treat the Term NPI in the manner provided under the Old Proposed Regulations, which were proposed at the time the Term NPI was transferred to the Trust and Trust Units were issued. Under this approach, each payment (at the time the amount of such payment becomes fixed) made to the Trust with respect to the Term NPI will be treated first as a payment of interest to the extent of interest deemed accrued under the OID rules and the excess (if any) will be treated as a payment of principal. The total amount treated as principal will be limited to a portion of the purchase price of each Depositary Unit allocated to the Term NPI. For purposes of determining the amount of accrued interest, the Old Proposed Regulations required the use of the Applicable Federal Rate based on the due date of the final payment due under the terms of the production payment, which for the Term NPI is May 15, 2013.

Unitholders are also required to recognize and report OID interest income attributable to the Treasury Obligations. In general, the total amount of OID a Unitholder is required to recognize will be calculated as the difference between the amount of the purchase price of a Depositary Unit allocated to the Treasury Obligations and the pro rata portion of the face amount of such Treasury Obligations attributable to the Depositary Unit. The amount of OID so calculated is included in income by a Unitholder on the basis of a constant interest rate computation.

Royalty Income and Depletion

The income from the Royalty NPI is royalty income subject to an allowance for depletion. The depletion allowance must be computed separately by each Unitholder for each oil or gas property (within the meaning of Code Section 614). The IRS presently takes the position that a net profits interest burdening multiple properties is one property for depletion purposes. Accordingly, the tax information reports that the Trust provides to Unitholders and the IRS have reported all production attributable to the Royalty NPI as production attributable to a single property for depletion purposes. Such reporting treatment is expected to continue until at least the IRS position on such treatment is changed.

The allowance for depletion with respect to a property is determined annually and is the greater of cost depletion or, if allowable, percentage depletion. Percentage depletion is generally available to independent producers (generally persons who are not substantial refiners or retailers of oil or gas or their primary products) on the equivalent of 1,000 barrels of production per day. Percentage depletion is a statutory allowance equal to 15% of the gross income from production from a property which is included in income by a taxpayer.

13

Percentage depletion is subject to a net income limitation which is 100% of the taxable income from the property, computed without regard to depletion deductions and certain loss carrybacks. A taxpayer s total percentage depletion deduction for all properties for a taxable year is limited to 65% of the taxpayer s taxable income for the year, before percentage depletion and certain other deductions. Unlike cost depletion, percentage depletion is not limited to the adjusted tax basis of the property, although it reduces that adjusted tax basis (but not below zero).

In computing cost depletion for each property for any year, the adjusted tax basis of that property at the end of that year is divided by the estimated total units (Mcf of gas) recoverable from that property to determine the per-unit allowance for such property. The per-unit allowance is then multiplied by the number of units produced and sold from that property during the year. Cost depletion for a property cannot exceed the adjusted tax basis of such property. While the Trust is treated as a grantor trust for Federal income tax purposes, each Unitholder computes cost depletion by using as his basis for the property the portion of his cost basis for his Depositary Units that is allocated first to the NPI and second to the Royalty NPI. Information is provided by the Trustee to each Unitholder reflecting how that basis should be allocated.

Section 29 Credit

Eastern American believes that most of the production attributable to the Royalty NPI is gas produced from Devonian shale or a tight formation. Provided a number of requirements are met, taxpayers are entitled to the Section 29 Credit for gas produced from Devonian shale or a tight formation. The Section 29 Credit generally applies only to gas produced from Devonian shale or a tight formation in the United States and sold to an unrelated party prior to January 1, 2003, from wells drilled after December 31, 1979, and prior to January 1, 1993. Additionally, the Section 29 Credit applies only to gas produced from a tight formation which, as of April 20, 1977, was committed or dedicated to interstate commerce (as defined in Section 2(18) of the Natural Gas Policy Act, as in effect on November 5, 1990), or which is produced from a well drilled after November 5, 1990. A Unitholder is eligible to claim the Section 29 Credit with respect to certain sales of such gas attributable to the Royalty NPI.

Section 29 Credits resulting from an investment in Depositary Units may only be used to reduce a taxpayer s regular income tax liability and generally may not be used to reduce a taxpayer s liability for alternative minimum tax. Section 29 Credits available to a taxpayer in any taxable year may not be carried back but may be carried forward for use by that taxpayer in a subsequent tax year only in a limited fashion. See Alternative Minimum Tax below.

The Section 29 Credit is not available for production after December 31, 2002. Congress in past years has considered, without enacting, legislation to extend energy tax credits such as the Section 29 Credit beyond their expiration date or to create new similar credits. The potential effect that enactment of any such possible legislation may have on Unitholders in the future is unknown.

On March 23, 1999, the United States Tax Court of Appeals for the Tenth Circuit affirmed a lower court decision in ***True Oil Company v.*** C.I.R. 170 F.3d 1294. The Court ruled that, in order to be eligible for credits under Section 29 of the Internal Revenue Code, each well from which gas is produced from Devonian shale or a tight formation must receive a determination from the Federal Energy Regulatory Commission (FERC) that the gas produced is, in fact, produced from Devonian shale or a tight formation. Eastern American has verified that most producing gas wells subject to the Royalty NPI have received a well category determination from FERC. Should the Internal Revenue Service challenge the amount of the Trust s production qualifying for Section 29 Credits, a Unitholder might not be able to claim the benefit of Section 29 credits for production attributable to a well that did not receive a FERC determination. If successful, such a challenge could affect the tax reporting for such credits for tax years examined by the IRS and any subsequent tax years. However, it should be noted that under current legislation the Section 29 credit is no longer available for production after December 31, 2002.

Other Income and Expenses

From time to time the Trust may generate interest income on funds held as a reserve or held until the next distribution date. Expenses of the Trust include administrative expenses of the Trustee. Under the Code, certain miscellaneous itemized deductions of an individual taxpayer are deductible only to the extent that in the aggregate they exceed 2% of the taxpayer s adjusted gross income. Certain administrative expenses attributable to the Trust Units may have to be aggregated with an individual Unitholder s other miscellaneous itemized deductions to determine the excess over 2% of adjusted gross income. To date the amount of such expenses has not been significant in relation to the Trust s income.

Alternative Minimum Tax

The Code imposes a minimum tax (known as an alternative minimum tax or AMT) on each taxpayer to the extent that his tentative minimum tax in any taxable year exceeds his regular tax for that year. For purposes of computing the AMT, the taxpayer s taxable income is recomputed with various adjustments plus items of tax preference .

A taxpayer is generally entitled to a credit against, or reduction in, his regular tax liability in a subsequent year in an amount equal to the AMT he pays for a prior taxable year. That credit can only be used to reduce his regular tax liability for that subsequent year to the extent his regular tax liability for that subsequent year exceeds his tentative minimum tax liability for that subsequent year, however.

The Section 29 Credit allowable to a taxpayer as a reduction of his liability for any taxable year cannot exceed the excess of his regular tax liability for such taxable year, as reduced by his foreign tax credits and certain nonrefundable credits, over his tentative minimum tax liability for that year. Any amount of Section 29 Credit disallowed for the tax year solely because of this limitation will increase a taxpayer s credit for the prior year s AMT, as described above. There is no provision for the carryback or carryforward of the Section 29 Credit in any other circumstances. Therefore, a Unitholder may not receive the full benefit of available Section 29 Credits, depending on his particular AMT circumstances.

Since the effect of the AMT varies depending upon each Unitholder s personal tax and financial position, each Unitholder is advised to consult with his own tax advisor concerning the effect of the AMT on him and Section 29 Credits attributable to an investment in the Depositary Units.

Non-Passive Activity

The income, credits and expenses of the Trust are not taken into account in computing the passive activity losses and income under Code Section 469 for a Unitholder who acquires and holds Depositary Units as an investment and did not acquire them in the ordinary course of business.

Unrelated Business Taxable Income

Certain organizations that are generally exempt from tax under Code Section 501 are subject to tax on certain types of business income defined in Code Section 512 as unrelated business income. The income of the Trust is not unrelated business taxable income within the meaning of Code Section 512 so long as the Trust Units are not debt-financed property within the meaning of Code Section 524(b). In general, a Trust Unit would be debt-financed if the Unitholder incurs debt to acquire a Trust Unit or otherwise incurs or maintains a debt that would not have been incurred or maintained if such Trust Unit had not been acquired. Legislative proposals have been made from time to time which, if adopted, would result in the treatment of income attributable to the Royalty NPI as unrelated business income.

Sale of Depositary Units; Sale of Trust Units or Treasury Obligations

Generally, a Unitholder will realize gain or loss on the sale or exchange of his Depositary Units measured by the difference between the amount realized on the sale or exchange and his adjusted basis for such Depositary Units. Gain or loss on the sale of Depositary Units by a Unitholder who is not a dealer with respect to such Depositary Units and who has a holding period for the Depositary Units of more than one year will be treated as long-term capital gain or loss except to the extent of the depletion recapture amount and any accrued market discount as explained below. A Unitholder s initial basis in his Depositary Units is equal to the amount paid for such Depositary Units. Such basis is increased by the amount of OID income recognized by the Unitholder attributable to the Treasury Obligations. Such basis is reduced by deductions for depletion claimed by the Unitholder (but not below zero). In addition, such basis is reduced by the amount of any payments attributable to the Term NPI which are treated as payments of principal under the OID rules.

For Federal income tax purposes, the sale of a Depositary Unit is treated as a sale by the Unitholder of his interest in the Treasury Obligations and the assets of the Trust. Thus, upon the sale of Depositary Units, a Unitholder must treat as ordinary income his depletion recapture amount, which is an amount equal to the lesser of (i) the gain on that sale attributable to disposition of the Royalty NPI or (ii) the sum of the prior depletion deductions taken with respect to the Royalty NPI (but not in excess of the initial basis of such Depositary Units allocated to the Royalty NPI). It is possible that the IRS would take the position that a portion of the sales proceeds is ordinary income to the extent of any accrued income at the time of sale allocable to the Depositary Units sold, but which is not distributed to the selling Unitholder.

A Unitholder who allocates his purchase price (or is required to allocate his purchase price) to the Treasury Obligations in an amount less than the sum of (a) his share of the initial issue price of the Treasury Obligations and (b) his share of OID income recognized by prior holders of the Treasury Obligations (any such difference represents market discount) will generally be required to recognize ordinary income to the extent of any accrued market discount upon sale of the Depositary Units. In general, accrued market discount is an amount which bears the same ratio to total market discount as the number of days which a Unitholder holds a Depositary Unit bears to the number of days after the date the Unitholder acquired the Depositary Unit and up to and including the Liquidation Date.

Withdrawal of Trust Units or Treasury Obligations

A Unitholder will recognize no gain or loss upon the withdrawal of the Trust Units or Treasury Obligations from the Depositary. A sale of the Trust Units or the Treasury Obligations will result in the recognition of income or loss.

Sale of Net Profits Interests or Production Payment

A sale by the Trust of Net Profits Interests are treated for Federal income tax purposes as a sale of Net Profits Interests by a Unitholder. Thus, a Unitholder will recognize gain or loss on a sale of Net Profits Interests by the Trust. A portion of that income may be treated as ordinary income to the extent of depletion recapture. Receipt by the Trust of proceeds drawn from the letter of credit supporting Eastern Marketing s obligations under the Gas Purchase Contract is, in certain cases, in consideration for the conveyance to Eastern Marketing of a production payment interest in reserves attributable to the Net Profits Interests or to compensate the Trust for damages from a breach of the Gas Purchase Contract. All or a portion of such proceeds may be treated as non-taxable loan proceeds attributable to a loan by Eastern Marketing resulting from the production payment, may be treated as ordinary income not subject to depletion or may receive some other treatment, depending upon facts existing at that time. To the extent receipt of such proceeds is attributable to a sale of reserves by the Trust, depletion and Section 29 Credits available to the Unitholders for subsequent periods is reduced.

Backup Withholding

In general, distributions of Trust income are not subject to backup withholding unless (i) the Unitholder is an individual or other noncorporate taxpayer and (ii) such Unitholder fails to comply with certain reporting procedures.

Tax Shelter Registration

The Trust has been registered with the IRS as a tax shelter, and has received tax shelter registration number 93040000163. A tax shelter, for purposes of the registration requirement, is an investment with respect to which a person could reasonably infer, from the representations made in connection with any offer for sale of any interest in the investment, that the tax shelter ratio for any investor may be greater than two to one as of the close of any of the first five years ending after the date on which the investment is offered for sale. The term tax shelter ratio with respect to an investment means the ratio that the aggregate amount of gross deductions for any investor, determined without regard to income derived from the investment, plus 350% of the credits that are potentially available to an investor, bears to the investment base for the year. The investment base is equal to the cash, plus the adjusted basis (which may be less than the fair market value) of any other property invested. Certain borrowings, however, including those from other participants in the venture, are excluded from the investment base. While Eastern American has no knowledge of any such borrowings, it is possible that, due to such borrowings, the investment base of an investor would be substantially reduced or eliminated.

A Unitholder who sells or otherwise transfers a Trust Unit must furnish to the transferee the tax shelter registration number set forth above. The penalty for failure of the transferor of a Trust Unit to furnish such tax shelter registration number to a transferee is $100 for each such failure. Unitholders must disclose the tax shelter registration number of the Trust on Form 8271 to be attached to the tax return on which any deduction, loss, credit or other benefit generated by the Trust is claimed or income of the Trust is included. A Unitholder who fails to disclose the tax shelter registration number on his return, without reasonable cause for such failure, will be subject to a $250 penalty for each such failure. (Any penalties discussed herein are not deductible for income tax purposes.)

ISSUANCE OF A TAX SHELTER REGISTRATION NUMBER DOES NOT INDICATE THIS INVESTMENT OR THE CLAIMED TAX BENEFITS HAVE BEEN REVIEWED, EXAMINED OR APPROVED BY THE IRS.

STATE TAX CONSIDERATIONS

The following is intended as a brief summary of certain information regarding state income taxes and other state tax matters affecting individual Unitholders. Unitholders are urged to consult their own legal and tax advisors with respect to these matters.

The Trust owns the Net Profits Interests burdening the Underlying Properties located in the states of Pennsylvania and West Virginia. Both of these states have income taxes applicable to individuals and may require the Trust to withhold taxes from distributions made to nonresident Unitholders. Withholding, if required, is at the rate of 4% of taxable income attributable to West Virginia and 2.8% of taxable income attributable to Pennsylvania. A Unitholder may be required to file state income tax returns and/or to pay taxes in these states and may be subject to penalties for failure to comply with such requirements. Generally, Unitholders may treat state income taxes that the Trust has withheld as having been paid by them to the state for which they were withheld. Unitholders may be able to treat any taxes that they have paid or that have been withheld and paid to West Virginia or Pennsylvania as a deduction in computing Federal income tax, or as a credit or a deduction in computing another state s income tax.

Unitholders receive information concerning the Depositary Units and the Trust Units sufficient to identify the income from Depositary Units that is allocable to each state. Holders of Depositary Units should consult their own tax advisors to determine their income tax filing requirements with respect to their share of income of the Trust allocable to states imposing a tax on such income.

The Trust Units and therefore also the Depositary Units may constitute real property or an interest in real property under the tax, inheritance, estate and probate laws of either or both of Pennsylvania and West Virginia. If the Depositary Units are held to be real property or an interest in real property under the laws of a state in which the Underlying Properties are located, the holders of Depositary Units may be subject to ad valorem or other property tax, devolution, probate and administration laws, and inheritance or estate and similar taxes, under the laws of such state.

Available Information

The Trust does not maintain an internet address or a website, and therefore does not make copies of its reports under the Exchange Act available in that manner. The Trust s filings under the Exchange Act are available electronically from the website maintained by the Securities and Exchange Commission at http://www.sec.gov. The Trust will also provide electronic copies of its recent filings free of charge upon request to the Trustee, and will provide paper copies of its recent filings for its costs of reproduction upon request to the Trustee.

Item 2. *Properties.*

Reference is made to Item 1 of this Form 10-K.

Item 3. *Legal Proceedings.*

None

Item 4. *Submission of Matters to a Vote of Unitholders.*

There were no matters submitted to a vote of Unitholders during the quarter ended December 31, 2003.

PART II

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

The Depositary Units are traded on the New York Stock Exchange under the ticker symbol NGT . The high and low prices and distributions paid during the quarters in the three-year period ended December 31, 2003 were as follows:

Quarter		**High**		**Low**		**Distributions Paid**
2001:						
First (to March 31, 2001)	$	18.25	$	16.00	$	0.63
Second (to June 30, 2001)	$	19.95	$	17.08	$	0.56
Third (to September 30, 2001)	$	19.44	$	16.91	$	0.42
Fourth (to December 31, 2001)	$	19.38	$	17.75	$	0.30
2002:						
First (to March 31, 2002)	$	19.00	$	17.22	$	0.28
Second (to June 30, 2002)	$	18.40	$	17.44	$	0.33
Third (to September 30, 2002)	$	19.00	$	16.50	$	0.34
Fourth (to December 31, 2002)	$	19.22	$	17.90	$	0.37
2003:						
First (to March 31, 2003)	$	19.58	$	18.70	$	0.38
Second (to June 30, 2003)	$	22.28	$	18.87	$	0.52
Third (to September 30, 2003)	$	23.55	$	20.83	$	0.51
Fourth (to December 31, 2003)	$	26.03	$	22.10	$	0.41

At March 8, 2004, the 5,900,000 Depositary Units outstanding were held by approximately 298 Unitholders of record.

With respect to the Treasury Obligations, the high and low closing prices per $1,000 face amount for the period from October 1, 2003 to December 31, 2003 were $665.10 and $634.00, respectively. The closing price on December 31, 2003 was $658.60 per $1,000 face amount.

During the fourth quarter of 2003, there were no purchases of Units made by or on behalf of the Trust or any affiliated purchaser as defined in Rule 10b-18 (a) (3) under the Exchange Act.

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

	December 31, 2003	December 31, 2002	December 31, 2001	December 31, 2000	December 31, 1999
Distributable Income	$ 10,947,816	$ 7,808,725	$ 11,268,383	$ 9,776,735	$ 8,561,984
Distribution Amount	$ 10,732,816	$ 7,808,725	$ 11,268,383	$ 9,776,735	$ 8,561,984
Distributable Income per unit	$ 1.86	$ 1.32	$ 1.91	$ 1.66	$ 1.45
Distribution Amount per unit	$ 1.82	$ 1.32	$ 1.91	$ 1.66	$ 1.45
Total assets at year end	$ 37,436,640	$ 41,006,654	$ 45,129,170	$ 50,964,669	$ 55,251,901

Item 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***.

General

The Trust does not conduct any operations or activities. The Trust s purpose is, in general, to hold the Net Profits Interests, to distribute to Unitholders cash which the Trust receives in respect of the Net Profits Interests and to perform certain administrative functions in respect of the Net Profits Interests and the Depositary Units. The Trust derives substantially all of its income and cash flows from the Net Profits Interests.

Under the Gas Purchase Contract, through the Primary Term ending December 31, 1999, Eastern Marketing purchased gas from the Trust at an Index Price calculated based on a Fixed Price component (escalating at 5% a year and carrying a 66-2/3% weighting) and a Variable Price component (varying with the Henry Hub market price as described below and carrying a 33-1/3% weighting), subject to a minimum Floor Price (as defined in the Gas Purchase Contract). Since January 1, 2000, and the end of the Primary Term, Eastern Marketing has purchased gas from the Trust at an Index Price composed only of the Variable Price component, and not subject to any minimum Floor Price. The Variable Price for any quarter is equal to the Henry Hub Average Spot Price (as defined) per MMBtu plus $0.30 per MMBtu, multiplied by 110% to effect a fixed adjustment for Btu content. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter equal to the price obtained with respect to each of the three months in such quarter, in the manner specified below, and then taking the average of the prices determined for each of such three months. The price determined for any month of such quarter is equal to the average of (i) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in *The Wall Street Journal*, for such contracts which expired in each of the five months prior to such month, (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in *The Wall Street Journal*, for such contracts which expire during such month and (iii) the closing settlement price per MMBtu of Henry Hub Gas Futures Contracts determined as of the contract settlement date for such month, as reported in *The Wall Street Journal*, for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub which is traded on the New York Mercantile Exchange.

Accordingly, the price payable to the Trust for production may vary based on fluctuations in natural gas futures prices during the relevant calculation period. The price payable to the Trust will have a direct impact, positively or negatively, on the quarterly distributions payable by the Trust to the Unitholders.

During 2002, Eastern American was asked to sell 3 wells in which the Trust owned a Net Profits Interest (the Western Pocahontas #7, #8 and #10 wells). The party seeking to purchase the wells owned the right to mine for coal on such properties (the Coal Lessee). The Coal Lessee stated that the wells would materially interfere with the Coal Lessee s proposed mining operations.

Eastern American reviewed the Trust Agreement and production from these wells, and determined that the Net Profits Interest associated with the Western Pocahontas # 7 well accounted for more than 0.25% of the total production from the Underlying Properties for the prior twelve (12) month period. Eastern American advised the Coal Lessee that it could not sell this well.

Subsequently, the Coal Lessee asserted that the coal estate in the relevant Underlying Properties was the dominate estate and that under the relevant oil and gas leases and applicable case law, the Coal Lessee could cause the Trust and Eastern American to plug and abandon the well. Eastern American and the Trust did not necessarily agree with the Coal Lessee position, however, and in an effort to avoid litigation, the Trust and Eastern American entered into a Settlement Agreement and Release of All Claims with the Coal Lessee pursuant to which Eastern agreed to sell the Western Pocahontas # 7 well for the amount of $426,187. The Trust s share of the proceeds of $303,438 was included in Distributable Income to the Trust during the year ended December 31, 2002. The Coal Lessee purchased the two additional wells, the Western Pocahontas # 8 and #10 for the amount of $209,561. The Trust s share of the proceeds of $188,605 was also included in the Distributable Income of the Trust during the year ended December 31, 2002.

During 2003, a Coal Lessee contacted Eastern American and inquired as to whether it would sell the U.S. Steel Well # 26, which is a well in which the Trust owns a Net Profits Interests. The Coal Lessee stated that the well would materially interfere with the Coal Lessee s proposed mining operations. Eastern American reviewed the Trust Agreement and production from this well to determine if it could cause the Trust to sell its Net Profits Interest in the well. Upon review, it was discovered that the Net Profits Interests associated with the U.S. Steel #26 well accounted for less than 0.25% of the total production from the Underlying Properties for the prior twelve (12) month period. Eastern American advised the Coal Lessee that it could sell this well. Eastern American received $11,437 for the sale of the U.S Steel Well #26. The Trust s share of the proceeds of $10,293 was included in the Distributable Income of the Trust during the year ended December 31, 2003.

Over the remaining life of the Trust, additional wells may need to be disposed of for similar reasons.

Critical Accounting Policies

The following is a summary of the critical accounting policies followed by the Trust.

Basis of Accounting:

The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America due to the following; i) certain cash reserves may be established for contingencies which were not accrued in the financial statements; ii) amortization of the Net Profits Interests in gas properties is charged directly to Trust Corpus; and iii) the sale of the Net Profits Interests is reflected in the Statements of Distributable Income as cash proceeds to the Trust.

Net Profits Interests in Gas Properties:

The Net Profits Interests in gas properties are periodically assessed to determine whether their net capitalized cost is impaired. The Trust will determine if a writedown is necessary to its investment in the Net Profits 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 writedown to the extent that the net capitalized costs exceed the discounted future net revenues attributable to proved gas reserves of the Underlying Properties. Any such writedown would not reduce distributable income, although it would reduce Trust Corpus.

Amortization of the Net Profits Interests in gas properties is calculated on a units-of-production basis, whereby the Trust s cost basis in the properties is divided by total Trust 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 Net Profits Interest impairment test and the determination of amortization rates are dependent on estimates of proved gas reserves attributable to the Trust. Numerous uncertainties are inherent in estimating reserve volumes and values, including economic and operating conditions, and such estimates are subject to change as additional information becomes available.

Liquidity and Capital Resources

The Trust has no source of liquidity or capital resources other than the distributions received from the Net Profits Interests.

In accordance with the provisions of the Conveyances, generally all revenues received by the Trust, net of Trust administrative expenses and the amount of established reserves, are distributed currently to the Unitholders.

The Trust did not have any contractual obligations as of December 31, 2003. At December 31, 2003, the Trust had accounts payable of $161,772 and distributions payable of $2,417,202.

Results of Operations

2003 Compared with 2002

The Trust s distributable income was $10,947,816 for the twelve months ended December 31, 2003 as compared to $7,808,725 for the twelve months ended December 31, 2002. This increase was due to an increase in Royalty Income for the twelve months ended December 31, 2003 ($13,177,510) as compared to the twelve months ended December 31, 2002 ($9,024,646). The increase in Royalty Income was due to an increase in the average price payable to the Trust under the Gas Purchase Contract as discussed below ($6.086 per Mcf for the twelve months ended December 31, 2003; $3.829 per Mcf for the twelve months ended December 31, 2002). This increase was offset by a decrease in production of gas attributable to the Net Profits Interests for the twelve months ended December 31, 2003 (2,161 Mmcf) as compared to the twelve months ended December 31, 2002 (2,357 Mmcf). The decline in production is primarily attributable to natural production declines and the sale of wells. Taxes on production and property were $897,881 for the twelve months ended December 31, 2003 as compared to $613,115 for the twelve months ended December 31, 2002. The increase in taxes is due directly to the increase in Royalty Income as discussed above. Trust general and administrative expenses were $833,027 for the twelve months ended December 31, 2003 as compared to $594,921 for the twelve months ended December 31, 2002. The increase in general and administrative expenses was due primarily to an increase in legal fees of $145,269 and an $81,042 increase due to the timing of payments for tax and audit services performed as well as an increase in fees for such services. The distributable income includes Cash Proceeds on Sale of Net Profits Interests of $10,293 for the period ended December 31, 2003, while $492,043 was recognized in the corresponding prior twelve months.

During the twelve months ended December 31, 2003, the Trustee established a cash reserve in the amount of $215,000 to facilitate the payment of vendor invoices on a timely basis. No such reserve existed in the prior twelve months ended December 31, 2002. Establishing this reserve reduced distributions payable by $215,000 or $0.0365 per unit for the twelve months ended December 31, 2003. Amortization of Nets Profits Interests in Gas Properties was $4,053,133 for the twelve months ended December 31, 2003 as compared to $4,474,182 for the twelve months ended December 31, 2002. This decrease was primarily due to the decrease in production volumes.

The average price payable to the Trust for gas production attributable to the Net Profits Interests was $6.086 per Mcf for the twelve months ended December 31, 2003 and $3.829 per Mcf for the twelve months ended December 31, 2002. The price per Mcf was higher for the twelve months ended December 31, 2003 than for the corresponding twelve month period ended December 31, 2002 due to an increase in the average spot market price for gas delivered at the Henry Hub near Henry, Louisiana ($5.233 per Dth for the twelve months ended December 31, 2003; $3.181 per Dth for the twelve months ended December 31, 2002).

2002 Compared with 2001

The Trust s distributable income was $7,808,725 for the twelve months ended December 31, 2002 as compared to $11,268,383 for the twelve months ended December 31, 2001. This decrease was due to a decrease in Royalty Income for the twelve months ended December 31, 2002 ($9,024,646) as compared to the twelve months ended December 31, 2001 ($13,260,202). The decrease in Royalty Income was due to a decrease in the average price payable to the Trust under the Gas Purchase Contract as discussed below ($3.829 per Mcf for the twelve months ended December 31, 2002; $5.316 per Mcf for the twelve months ended December 31, 2001). This decrease was also due to a decrease in production of gas attributable to the Net Profits Interests for the twelve months ended December 31, 2002 (2,357 Mmcf) as compared to the twelve months ended December 31, 2001 (2,489 Mmcf). The decline in production is primarily attributable to natural production declines and the sale of wells. Taxes on production and property were $613,115 for the twelve months ended December 31, 2002 as compared to $900,951 for the twelve months ended December 31, 2001. The decrease in taxes is due directly to the decrease in Royalty Income as discussed above. Trust general and administrative expenses remained relatively constant for the twelve months ended December 31, 2002 as compared to the twelve months ended December 31, 2001. The distributable income includes Cash Proceeds on Sale of Net Profits Interests of $492,043 for the period ended December 31, 2002, while no such sales were recognized in the corresponding prior twelve months.

The average price payable to the Trust for gas production attributable to the Net Profits Interests was $3.829 per Mcf for the twelve months ended December 31, 2002 as compared to $5.316 per Mcf for the twelve months ended December 31, 2001. The average price per Mcf was lower for the twelve months ended December 31, 2002 than the corresponding twelve month period ended December 31, 2001 due to a decrease in the average spot market price for gas delivered at the Henry Hub, near Henry, Louisiana ($3.181 per MMBtu for the twelve months ended December 31, 2002; $4.532 per MMBtu for the twelve months ended December 31, 2001).

Off-Balance Sheet Arrangements

The Trust does not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on the Trust s financial condition, changes in financial condition, revenue or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

The Trust does not engage in any operations, and does not utilize market risk sensitive instruments, either for trading purposes or for other than trading purposes. As described in detail elsewhere herein, the Depositary Units consist of beneficial ownership of one unit of beneficial interest in the Trust and a $20 face amount beneficial ownership interest in a $1,000 face amount zero coupon Treasury Obligation maturing on May 15, 2013. High and low price information for the Treasury Obligations is included under Item 5. As described in detail elsewhere herein, gas production attributable to the Net Profits Interest is sold to a wholly owned subsidiary of Eastern American pursuant to the Gas Purchase Contract described herein.

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

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 Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and regulations. Disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed by the Trust is accumulated and communicated by several parties, including without limitation, the working interest owner, Eastern American Energy Corporation (Eastern American), and the independent reserve engineer to The Bank of New York, 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 December 31, 2003, the Trustee carried out an evaluation of the Trustee s disclosure controls and procedures. Patrick Tadie, a Vice President of the Trustee, has concluded that the controls and procedures are effective at the reasonable assurance level, while noting certain limitations on disclosure controls and procedures as set forth below.

Due to the contractual arrangements of (i) the Trust Agreement, and (ii) the rights of the Trustee under the Conveyances regarding information furnished by Eastern American, there are certain potential weaknesses that may limit the effectiveness of disclosure controls and procedures established by the Trustee or its employees and their ability to verify the accuracy of certain financial information. The contractual limitations creating potential weaknesses in disclosure controls and procedures may be deemed to include:

Eastern American and its consolidated subsidiaries manage (i) historical operating data, including production volumes, marketing of products, operating and capital expenditures, environmental and other liabilities, the effects of regulatory changes and the number of producing wells and acreage, (ii) plans for future operating and capital expenditures and (iii) geological data relating to reserves. While the Trustee requests material information for use in periodic reports as part of its disclosure controls and procedures, the Trustee does not manage this information, and relies entirely on Eastern American to provide accurate and timely information when requested for use in the Trust s reports.

Under the terms of the Trust Agreement, the Trustee is entitled to, and in fact does rely, upon certain experts in good faith, including (i) the independent reserve engineer with respect to the annual reserve report, which includes projected production, operating expenses and capital expenses, and (ii) the independent auditors the Trustee has contracted with respect to the annual audit and quarterly reviews of financial data provided by Eastern American. Other than contracting independent auditors and reviewing the financial and other information provided to the Trust by Eastern American on a quarterly basis, the Trustee makes no independent or direct verification of this financial or other information. While the Trustee has no reason to believe its reliance upon experts is unreasonable, this reliance on experts and restricted access to information may be viewed as a weakness.

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

Changes in Internal Controls

To the knowledge of the Trustee, there have been no significant changes in the Trust s internal controls that could significantly affect the Trust s internal controls subsequent to the date the Trustee completed its evaluation. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal controls of Eastern American.

PART III

Item 10. ***Directors and Executive Officers of the Registrant.***

The Trust has no directors or executive officers. The Trustee is a corporate trustee which may be removed by the affirmative vote of holders of a majority of the Trust Units then outstanding at a meeting of the Unitholders of the Trust at which a quorum is present. The Trust is not required to and does not hold annual meetings of the Unitholders.

The Trust also does not have an audit committee or body serving a similar function, and does not have an audit committee financial expert . The Trust has not adopted a code of ethics, as the Trust has no directors, officers, or employees. The Trust has not adopted a process by which Unitholders may communicate with Board Members, as the Trust has no board members or persons fulfilling a similar function. Unitholders may contact the Trustee at the following address:

The Bank of New York

Care of BNY Midwest Trust Company

2 North LaSalle Street, Suite 1020

Chicago, Illinois 60602

Item 11. ***Executive Compensation.***

The Trust has no officers or directors, and is administered by the Trustee. For the years ended December 31, 2003, 2002 and 2001, the Trustee received $45,000 annually, as Trustee fees and $491,803, $263,713 and $261,662, respectively, as reimbursement of legal, accounting, and other professional expenses for such services.

Item 12. ***Security Ownership of Certain Beneficial Owners, Management and Related Unitholder Matters.***

(a) Security Ownership of Certain Beneficial Owners.

Based on filings with the Securities and Exchange Commission, the Trust is not aware of any person owning beneficially more than five percent of the Units as of March 1, 2004.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

The Trust knows of no arrangements, including the pledge of securities of the Trust, the operation of which may at a subsequent date result in a change in control of the Trust.

(d) Securities authorized for issuance under equity compensation plans.

The Trust has no equity compensation plans and therefore has not included tabular disclosures related thereto.

Item 13. ***Certain Relationships and Related Transactions.***

None.

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

Audit Fees

The fees, including expenses, PricewaterhouseCoopers LLP billed the Trust for each of the last two fiscal years for professional services rendered in connections with the audits of the Trust s annual financial statements and review of the Trust quarterly interim financial statements were $83,500in 2002 and $73,000 in 2003.

Audit-Related Fees

PricewaterhouseCoopers LLP did not bill the Trust any additional fees in the last two fiscal years for assurance and related services that are reasonably related to the performance of the audit or review of the Trust s Financial Statements.

Tax Fees

The fees, including expenses, PricewaterhouseCoopers LLP billed the Trust for each of the last two fiscal years for compliance, tax advice, or planning were $139,921in 2002 and $126,681 in 2003.

All Other Fees

PricewaterhouseCoopers LLP did not bill the trust any additional fees in the last two fiscal years for products and services provided by PricewaterhouseCoopers LLP, other than services reported above.

Pre-Approval Policies

The Trust does not have an audit committee or body performing a similar function. Pre-approval of all services performed by PricewaterhouseCoopers LLPand approval of the related fees is granted by the Trustee.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules, and Reports on Form 8-K.***

Financial Statements

The following financial statements are included in this Annual Report on Form 10-K on the pages indicated:

Schedules

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

Exhibits

Except as otherwise indicated below, all exhibits, except Exhibit 31.0 and Exhibit 32.0, are incorporated herein by reference to the indicated exhibits to filings previously made by the registrant with the Securities and Exchange Commission. All references are to the registrant s Registration Statement on Form S-1, Registration No. 33-56336, except for Exhibit 3.1, which is incorporated by reference to the Registrant s Annual Report on Form 10-K for the year ended December 31, 1994.

		Exhibit Number
3.1	Second Amended and Restated Trust Agreement of Eastern American Natural Gas Trust	3.1
4.1	Specimen Depositary Receipt	4.1
4.2	Form of NPI Royalty Deposit Agreement	4.2
10.1	Form of Conveyance	10.1
10.2	Form of Term NPI Conveyance	10.2
10.3	Form of Gas Purchase Contract between Eastern American Energy Corporation, Eastern American Marketing Corporation and Eastern American Natural Gas Trust	10.3
10.4	Form of Conveyance of Production Payment/Assignment of Production from Eastern American Natural Gas Trust to Eastern American Marketing Corporation	10.4
10.5	Form of Assignment and Standby Performance Agreement	10.5
31.0	Rule 13a-14(a)/15d-14(a) Certification	
32.0	Section 1350 Certification	

25

Reports on Form 8-K

None.

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 on this 10th day of March, 2004.

EASTERN AMERICAN NATURAL GAS TRUST

By:	The Bank of New York, Trustee
By:	/s/ Patrick Tadie
Name:	Patrick Tadie
Title:	Vice President

The Registrant, Eastern American Natural Gas Trust, has no principal executive officer, principal financial officer, controller or principal accounting officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided.

[Ryder Scott Company, Independent Petroleum Engineers Letterhead]

January 21, 2004

Eastern American Natural Gas Trust

The Bank of New York

2 North LaSalle Street, Suite 1020

Chicago, Illinois 60602

Gentlemen:

Pursuant to your request, we present below estimates of the net proved reserves attributable to the interests of the Eastern American Natural Gas Trust (Trust) as of December 31, 2003. The Trust is a grantor trust formed to hold interests in certain domestic oil and gas properties owned by Eastern American Energy Corporation (EAEC), a wholly owned subsidiary of Energy Corporation of America (ECA). The interests conveyed to the Trust consist of a net profits interest derived from working and royalty interests in numerous properties. The Net Profits Interest consists of (1) a life-of-properties interest (Royalty NPI) and (2) a term interest (Term NPI). The properties included in the Trust are located in the states of Pennsylvania and West Virginia.

The estimated reserve quantities and future income quantities presented in this report are related to a large extent to hydrocarbon prices. Hydrocarbon prices in effect at December 31, 2003 were used in the preparation of this report as required by Securities and Exchange Commission (SEC) and Financial Accounting Standards Bulletin No. 69 (FASB 69) guidelines; however, actual future prices may vary significantly from December 31, 2003 prices for reasons discussed in more detail in other sections of this report. Therefore, quantities of reserves actually recovered and quantities of income actually received may differ significantly from the estimated quantities presented in this report.

	As of December 31, 2003		
	Gas (MMCF)	**Estimated Future Net Cash Inflows (M$)**	**Present Value At 10% (M$)**
Proved Net Developed			
Royalty NPI	14,142	64,646	27,357
Term NPI	8,568	42,743	29,092
Total	22,710	107,389	56,449

Reserve quantities are calculated differently for a Net Profits Interest because such interests do not entitle the Trust to a specific quantity of oil or gas but to 90 percent of the Net Proceeds derived therefrom beginning on January 1, 2004 for natural gas. Accordingly, there is no precise method of allocating estimates of the quantities of proved reserves attributable to the Net Profits Interest between the interest held by the Trust and the interests to be retained by EAEC. For purposes of this presentation, the proved reserves attributable to the Net Profits Interests have been proportionately reduced to reflect the future estimated costs and expenses deducted in the calculation of Net Proceeds with respect to the Net Profits Interests. Accordingly, the reserves presented for the Net Profits Interest reflect quantities of gas that are free of future costs or expenses based on the price and cost assumptions utilized in this report. The allocation of proved reserves of the Net Profits Interest between the Trust and EAEC will vary in the future as relative estimates of future gross revenues and future net incomes vary. Furthermore, EAEC requested that for purposes of our report the Royalty NPI be calculated beyond the Liquidation Date of May 15, 2013, even though by the terms of the Trust Agreement the Royalty NPI will be sold by the Trustee on or about this date and a liquidating distribution of the sales proceeds from such sale would be made to holders of Trust Units. The Trust Agreement provides that the Term NPI entitles the Trust to receive the net proceeds from the gas produced from the properties burdened by the Term NPI until the earlier of May 15, 2013 or until such time as 41,683 MMCF of gas has been produced. For purposes of this report, the Term NPI was limited to May 15, 2013.

All gas volumes are sales gas expressed in MMCF at the pressure and temperature bases of the area where the gas reserves are located. The estimated future net cash inflows are described later in this report.

The proved reserves presented in this report comply with the Securities and Exchange Commission s Regulation S-X Part 210.4-10 Sec. (a) as clarified by subsequent Commission Staff Accounting Bulletins, and are based on the following definitions and criteria:

Proved reserves of crude oil, natural gas, or natural gas liquids are estimated quantities that geological and engineering data demonstrate with reasonable certainty to be recoverable in the future from known reservoirs under existing conditions. Reservoirs are considered proved if economic producibility is supported by actual production or formation tests. In certain instances, proved reserves may be assigned on the basis of a combination of core analysis and electrical and other type logs which indicate the reservoirs are analogous to reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test. The area of a reservoir considered proved includes (1) that portion delineated by drilling and defined by fluid contacts, if any, and (2) the adjoining portions not yet drilled that can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Proved reserves are estimates of hydrocarbons to be recovered from a given date forward. They may be revised as hydrocarbons are produced and additional data becomes available. Proved natural gas reserves consist of non-associated, associated and dissolved gas. An appropriate reduction in gas reserves has been made for the expected removal of natural gas liquids, for lease and plant fuel, and for the exclusion of non-hydrocarbon gases if they occur in significant quantities.

Reserves that can be produced economically through the application of improved recovery techniques are included in the proved classification when these qualifications are met: (1) successful testing by a pilot project or the operation of an installed program in the reservoir provides support for the engineering analysis on which the project or program was based, and (2) it is reasonably certain the project will proceed. Improved recovery includes all methods for supplementing natural reservoir forces and energy, or otherwise increasing ultimate recovery from a reservoir, including (1) pressure maintenance, (2) cycling, and (3) secondary recovery in its original sense. Improved recovery also includes the enhanced recovery methods of thermal, chemical flooding, and the use of miscible and immiscible displacement fluids.

Estimates of proved reserves do not include crude oil, natural gas, or natural gas liquids being held in underground or surface storage.

(i) developed reserves which are those proved reserves reasonably expected to be recovered through existing wells with existing equipment and operating methods, including (a) developed producing reserves which are those proved developed reserves reasonably expected to be produced from existing completion intervals now open for production in existing wells, and (b) developed non-producing reserves which are those proved developed reserves which exist behind the casing of existing wells which are reasonably expected to be produced through these wells in the predictable future where the cost of making such hydrocarbons available for production should be relatively small compared to the cost of a new well; and

(ii) undeveloped reserves which are those proved reserves reasonably expected to be recovered from new wells on undrilled acreage, from existing wells where a relatively large expenditure is required and from acreage for which an application of fluid injection or other improved recovery technique is contemplated where the technique has been proved effective by actual tests in the area in the same reservoir. Reserves from undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are included only where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation.

In accordance with the requirements of FASB 69, estimates of future cash inflows, future costs and future net cash inflows before income tax, as well as estimated reserve quantities, as of December 31, 2003 from this report are presented in the following table:

	As of December 31, 2003		
	Royalty NPI	**Term NPI**	**Totals**
Total Proved			
Future Cash Inflows (M$)	64,646	42,743	107,389
Future Costs			
Production (M$)	0	0	0
Development (M$)	0	0	0
Total Costs (M$)	0	0	0
Future Net Cash Inflows			
Before Income Tax (M$)	64,646	42,743	107,389
Present Value at 10%			
Before Income Tax (M$)	27,357	29,092	56,449

	As of December 31, 2003		
	Royalty NPI	**Term NPI**	**Totals**
Proved Net Developed Reserves			
Gas (MMCF)	14,142	8,568	22,710
Proved Net Undeveloped Reserves			
Gas (MMCF)	0	0	0
Total Proved Net Reserves			
Gas (MMCF)	14,142	8,568	22,710

For Net Profits Interest, the future cash inflows are, as described previously, after consideration of future costs or expenses based on the price and cost assumptions utilized in this report. Therefore, the future cash inflows are the same as the future net cash inflows. The effects of depreciation, depletion and federal income taxes have not been taken into account in estimating future net cash inflows.

EAEC furnished us gas prices in effect at December 31, 2003 and with its forecasts of future gas prices which take into account Securities and Exchange Commission guidelines, current market prices, contract prices and fixed and determinable price escalations where applicable. In accordance with Securities and Exchange Commission guidelines, the future gas prices used in this report make no allowances for future gas price increases or decreases which may occur as a result of inflation nor do they account for seasonal variations in gas prices which are likely to cause future yearly average gas prices to be somewhat higher than December gas prices. In those cases where contract market-out has occurred, the current market price was held constant to depletion of the reserves. In those cases where market-out has not occurred, contract gas prices including fixed and determinable escalations, exclusive of inflation adjustments, were used until the contract expired and then reduced to the current market price for similar gas in the area and held at this reduced price to depletion of the reserves.

This report utilized the terms of the gas contract between Eastern Marketing Corporation (a wholly owned subsidiary of EAEC) and the Trust. Gas price is to be determined by a weighted price consisting of two components during a primary term defined to begin on January 1, 1993 and end December 31, 1999. The first component is the Fixed price which has been defined as $2.66 per Mcf beginning January 1, 1993. This price escalates 5 percent per year on January 1 of each year during the primary term beginning in 1994. The second component is the Variable price which for any quarter is equal to the Henry Hub Average Spot Price (as defined) per MMBtu, plus $0.30 per MMBtu, multiplied by 110 percent to effect a Btu adjustment. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter as the average price of the three months in such quarter where each month s price is equal to the average of (i) the final settlement prices per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in the Wall Street Journal, for such contracts which expired in each of the five months prior to each month of such quarter, (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in the Wall Street Journal, for such contracts which expire during such month and (iii) the closing settlement prices per MMBtu of Henry Hub Gas Futures Contracts for such month, as reported in the Wall Street Journal, for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub which is traded on the New York Mercantile Exchange. The weighted average price is determined by giving the Fixed price a 66 2/3 percent weighting and the variable price a 33 1/3 percent weighting.

Since the primary term is complete, the purchase price under the gas contract will be equal to the Variable price. EAEC computed the Variable price under the gas contract as of December 31, 2003 as $5.724 per Mcf, utilizing $4.904 as the Henry Hub Average Spot Price computed in accordance with the gas contract.

Operating costs for the leases and wells in this report were supplied by EAEC and include only costs defined as applicable under terms of the Trust. The current operating costs were held constant throughout the life of the properties. This study does not consider the salvage value of the lease equipment or the abandonment cost.

No deduction was made for indirect costs such as general administration and overhead expenses, loan repayments, interest expenses, and exploration and development prepayments. No attempt has been made to quantify or otherwise account for any accumulated gas production imbalances that may exist.

Our reserve estimates are based upon a study of the properties in which the Trust has interests; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities which may exist nor were any costs included for potential liability to restore and clean up damages, in any, caused by past operating practices. EAEC informed us that it has furnished us all of the accounts, records, geological and engineering data and reports and other data as were required for our investigation. The ownership interests, terms of the Trust, prices, taxes, and other factual data furnished to us in connection with our investigation were accepted as represented. The estimates presented in this report are based on data available through March, 2003. The projections were developed for the EAEC reserve report effective July 1, 2003. EAEC has advised Ryder Scott that there has been no material change in the performance of these wells and therefore the July 1, 2003 projections developed for the EAEC report were mechanically adjusted to January 1, 2004 for use in this report.

At the time of formation of the Trust, EAEC assigned The Trust an interest in 65 undeveloped locations. During the period 1993 through 1998, EAEC has completed it s drilling obligation. A total of 59 wells were drilled over this period. Two wells were not drilled due to title failure and four wells were not drilled due to short spacing. Reserves and projections of future production are included for the four locations which were not drilled due to short spacing.

The reserves included in this report are estimates only and should not be construed as being exact quantities. They may or may not be actually recovered. Moreover, estimates of proved reserves may increase or decrease as a result of future operations of EAEC. Moreover, due to the nature of the Net Profits Interest, a change in the future costs, or prices different from those projected herein may result in a change in the computed reserves and the Net Proceeds to the Trust even if there are no revisions or additions to the gross reserves attributed to the property.

The future production rates from properties now on production may be more or less than estimated because of changes in market demand or allowables set by regulatory bodies. Properties which are not currently producing may start producing earlier or later than anticipated in our estimates of their future production rates.

The future prices received by EAEC for the sale of its production may be higher or lower than the prices used in this report as described above, and the operating costs and other costs relating to such production may also increase or decrease from existing levels; however, such possible changes in prices and costs were, in accordance with rules adopted by the Securities and Exchange Commission, omitted from consideration in preparing this report.

At the request of EAEC, we have included the following table which summarizes the total net reserves estimates from combined interest of EAEC and the Trust in the Underlying Properties:

Estimated Net Reserve Data

Certain Combined Leasehold Interests of

Eastern America Energy Corporation

And The Trust

As of December 31, 2003

SEC Parameters

	Proved		
	Developed	Undeveloped	Total Proved
Net Remaining Reserves			
Gas-MMCF	37,311	0	37,311

The estimated future net income associated with the foregoing volumes and the 10 percent discounted estimated future net income was $173,665,204 and $71,622,179, respectively. This evaluation utilizes the same price and cost assumptions that were utilized for evaluating the Trust and discussed earlier in the letter. The properties which are included in the Term NPI were allowed to run for their full economic life in this evaluation.

Neither Ryder Scott Company nor any of its employees has any interest in the subject properties and neither the employment to make this study nor the compensation is contingent on our estimates of reserves and future cash inflows for the subject properties.

Very truly yours,

RYDER SCOTT COMPANY, L.P.

Larry T. Nelms P. E.
Managing Senior Vice President

LTN:ph

EASTERN AMERICAN NATURAL GAS TRUST

FINANCIAL STATEMENTS

as of December 31, 2003 and 2002

and for the years ended

December 31, 2003, 2002 and 2001

REPORT OF INDEPENDENT AUDITORS

To the Unitholders and The Bank of New York,

As Trustee for Eastern American Natural Gas Trust:

We have audited the accompanying statements of assets, liabilities and trust corpus of Eastern American Natural Gas Trust (the Trust) as of December 31, 2003 and 2002, and the related statements of distributable income, and changes in trust corpus for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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 2 to the financial statements, these financial statements have been prepared on the basis of accounting prescribed by the Trust Agreement.

In our opinion, the financial statements audited by us present fairly, in all material respects, the financial position of the Trust at December 31, 2003 and 2002, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2003, on the basis of accounting described in Note 2.

/s/ PricewaterhouseCoopers LLP

Pittsburgh, Pennsylvania
March 5, 2004

EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

as of December 31, 2003 and 2002

		2003		2002
Assets:				
Cash	$	115,205	$	406
Net Proceeds Receivable		2,678,769		2,310,449
Net Profits Interests in Gas Properties		93,162,180		93,162,180
Accumulated Amortization		(58,519,514)		(54,466,381)
Total Assets	$	37,436,640	$	41,006,654
Liabilities and Trust Corpus:				
Trust General and Administrative Expenses Payable	$	161,772	$	145,098
Distributions Payable		2,417,202		2,165,757
Trust Corpus (5,900,000 Trust Units authorized and outstanding)		34,857,666		38,695,799
Total Liabilities and Trust Corpus	$	37,436,640	$	41,006,654

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

EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF DISTRIBUTABLE INCOME

for the years ended

December 31, 2003, 2002 and 2001

	2003	2002	2001
Royalty Income	$ 13,177,510	$ 9,024,646	$ 13,260,202
Operating Expenses:			
Taxes on production and property	897,881	613,115	900,951
Operating cost charges	510,032	501,738	513,107
Total Operating Expenses	1,407,913	1,114,853	1,414,058
Net Proceeds to the Trust	11,769,597	7,909,793	11,846,144
General and Administrative Expenses	(833,027)	(594,921)	(583,190)
Interest Income	953	1,810	5,429
Cash Proceeds on Sale of Net Profits Interests	10,293	492,043	0
Distributable Income	10,947,816	7,808,725	11,268,383
Cash Reserve	(215,000)	0	0
Distribution Amount	$ 10,732,816	$ 7,808,725	$ 11,268,383
Distributable Income Per Unit (5,900,000 units authorized and outstanding)	$ 1.8556	$ 1.3235	$ 1.9099
Distribution Amount Per Unit (5,900,000 units authorized and outstanding)	$ 1.8191	$ 1.3235	$ 1.9099

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

EASTERN AMERICAN NATURAL GAS TRUST

STATEMENTS OF CHANGES IN TRUST CORPUS

for the years ended

December 31, 2003, 2002 and 2001

	2003	2002	2001
Trust Corpus, Beginning of Period	$ 38,695,799	$ 43,169,981	$ 47,650,950
Distributable Income	10,947,816	7,808,725	11,268,383
Distributions Paid or Payable to Unitholders	(10,732,816)	(7,808,725)	(11,268,383)
Amortization of Net Profits Interests in Gas Properties	(4,053,133)	(4,474,182)	(4,480,969)
Trust Corpus, End of Period	$ 34,857,666	$ 38,695,799	$ 43,169,981

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

EASTERN AMERICAN NATURAL GAS TRUST

NOTES TO FINANCIAL STATEMENTS

1. Organization of the Trust:

The Eastern American Natural Gas Trust (the Trust) was formed under the Delaware Business Trust Act pursuant to a Trust Agreement (the Trust Agreement) among Eastern American Energy Corporation (Eastern American), as grantor, Bank of Montreal Trust Company, as Trustee, and Wilmington Trust Company, as Delaware Trustee (the Delaware Trustee). Effective May 8, 2000, The Bank of New York acquired the corporate trust business of The Bank of Montreal Trust Company. As a result, The Bank of New York serves as Trustee (the Trustee).

The purpose of the Trust is to acquire and hold net profits interests owned by Eastern American in 650 producing gas wells and 65 proved development well locations in West Virginia and Pennsylvania (the Underlying Properties). The Underlying Properties are operated by Eastern American. The Net Profits Interests (the Net Profits Interests) consist of a Royalty interest in 322 wells and a Term interest in the remaining wells and locations. Eastern American drilled 59 of the 65 development wells.

Four (4) of the remaining six (6) development wells were closely offset by third parties. Since the wells drilled by the third parties were within 1,000 feet of these development wells, Eastern American had a disagreement with the Trust over Eastern American s obligation to drill these closely offset development wells. The Trust has agreed that, in lieu of drilling these closely offset development wells Eastern American can provide the Trust, on an annual basis commencing on April 1, 1997, and over the remaining life of the Trust, a volume of gas which is equal to the projected volumes of the wells as if they had been drilled. These volumes have been estimated by the Ryder Scott Company.

The two (2) remaining development wells were not drilled because Eastern American was unable to cure various title defects associated with these wells. Eastern American advised the Trust that it made a diligent effort to cure title but was unsuccessful. In West Virginia, an oil and gas well cannot be drilled unless a full and complete 100% leasehold interest is first obtained. Drilling an oil and gas well without obtaining the entire leasehold estate would expose the oil and gas operator and the Trust to a possible suit for trespass. Pursuant to the Term Net Profits Interest Conveyance, if the state of title to the drill site to any development well renders such property undrillable in the good faith opinion of Eastern American under the Reasonably Prudent Operator Standard then such drill site(s) shall be construed as a development well(s). Consequently, Eastern American has fulfilled its commitment to the Trust to drill the required number of development wells.

On March 15, 1993, 5,900,000 depositary units were issued in a public offering at an initial public offering price of $20.50 per depositary unit. Each depositary unit consists of beneficial ownership of one unit of beneficial interest (Trust Unit) in the Trust and a $20 face amount beneficial ownership interest in a $1,000 face amount zero coupon United States Treasury Obligation (Treasury Obligation) maturing on May 15, 2013 (see Note 6). Of the net proceeds from such offering, $27,787,820 was used to purchase $118,000,000 in face amount of Treasury Obligations and $93,162,180 was paid to Eastern American in consideration for the conveyance of the Net Profits Interests to the Trust. The Trust acquired the Net Profits Interests effective as of January 1, 1993.

The Net Profits Interests are passive in nature, and neither the Trustee nor the Delaware Trustee has management control or authority over, nor any responsibility relating to, the operation of the properties subject to the Net Profits Interests. The Trust Agreement provides, among other things, that the Trust shall not engage in any business or commercial activity or acquire any asset other than the Net Profits Interests initially conveyed to the Trust; the Trustee may establish a reserve for payment of any liability which is contingent, uncertain in amount or that is not currently due and payable; the Trustee is authorized to borrow funds required to pay liabilities of the Trust, provided that such borrowings are repaid in full prior to further distributions to Unitholders; and the Trustee will make quarterly cash distributions to Unitholders from funds of the Trust.

2. Significant Accounting Policies:

The following is a summary of the significant accounting policies followed by the Trust.

Basis of Accounting:

The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America due to the following; i) certain cash reserves may be established for contingencies which were not accrued in the financial statements; ii) amortization of the Net Profits Interests in gas properties is charged directly to Trust Corpus; and iii) the sale of the Net Profits Interests is reflected in the Statements of Distributable Income as cash proceeds to the Trust.

Cash:

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

Net Profits Interests in Gas Properties:

The Net Profits Interests in gas properties are periodically assessed to determine whether their net capitalized cost is impaired. The Trust will determine if a writedown is necessary to its investment in the Net Profits 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 writedown to the extent that the net capitalized costs exceed the discounted future net revenues attributable to proved gas reserves of the Underlying Properties. Any such writedown would not reduce distributable income, although it would reduce Trust Corpus.

Significant dispositions or abandonment of the Underlying Properties are charged to Net Profits Interests and the Trust Corpus.

Amortization of the Net Profits Interests in gas properties is calculated on a units-of-production basis, whereby the Trust s cost basis in the properties is divided by total Trust 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 and Term Interests to the Trust was accounted for as a purchase transaction. The $93,162,180 reflected in the Statement of Assets, Liabilities and Trust Corpus as Net Profits Interests represents 5,900,000 Trust Units valued at $20.50 per depository unit less the $27,787,820 paid for Treasury obligations. The carrying value of the Trust s investment in the Royalty Interests is not necessarily indicative of the fair value of such Royalty Interests.

Revenues 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 distributable income, defined as Trust income available for distribution to Unitholders 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 also recognized on an accrual basis. Operating expenses which include taxes on production and operating cost charges are recognized as incurred pursuant to the Conveyances on a per well production basis. The payment provisions of the gas purchase contract between the Trust and Eastern Marketing Corporation require payment with respect to gas production for a calendar quarter to be made to the Trust on or before the tenth day of the third month following such quarter.

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.

Segment Information:

In 1998, the Trust adopted SFAS 131, Disclosure about Segments of an Enterprise and Related Information. The Trust s sole activity is earning royalty income from gas properties and, consequently, the Trust has only one operating segment, net profits interests in gas properties. Substantially all of the Trust s net profits interests are located in the Appalachian region.

3. Income Taxes:

Tax counsel to the Trust advised the Trust at the time of formation that, under then current tax laws, the Trust would be classified as a grantor trust for federal and state income tax purposes and, therefore, would not be subject to taxation at the Trust level. The Trust continues to be tax exempt. Accordingly, no provision for federal or state income taxes has been made. However, the opinion of tax counsel is not binding on taxing authorities.

The Unitholders are considered, for income tax purposes, to own the Trust s income and principal as though no trust were in existence. Thus, the taxable year for reporting a Unitholder s share of the Trust income, expense and credits are controlled by the Unitholder s taxable year and method of accounting, not the taxable year and method of accounting employed by the Trust.

4. Distributions to Unitholders:

The Trustee determines for each quarter the amount available for distribution to the Unitholders. Such amount will be equal to the excess, if any, of the cash received by the Trust, on or before the tenth day of the third month following the end of each calendar quarter ending prior to the dissolution of the Trust, from the Net Profits Interests then held by the Trust attributable to production during such quarter, plus, with certain exceptions, any other cash receipts of the Trust during such quarter, over the liabilities of the Trust paid during such quarter, subject to adjustments for changes made by the Trustee during such quarter in any cash reserves established for the payment of contingent or future obligations of the Trust. Cash received by the Trustee in a particular quarter from the Net Profits Interests will reflect actual gas production for a portion of such quarter and a production estimate for the remainder of such quarter, such estimate to be adjusted to actual production in the following quarter.

Net Proceeds Receivable included in the Statements of Assets, Liabilities and Trust Corpus as of December 31, 2003 are expected to be received by the Trust and distributed to the Unitholders on March 15, 2004 . The December 31, 2002 Net Proceeds Receivable were received and distributed by the Trust on March 17, 2003.

5. Related Party Transactions:

The Trust is responsible for paying all legal, accounting, engineering and stock exchange fees, printing costs and other administrative expenses incurred at the direction of the Trustee. The total of all Trustee fees and Trust administrative expenses was $536,803 for the year ended December 31, 2003, $308,713 for the year ended December 31, 2002, and $306,662 for the year ended December 31, 2001. In accordance with the Trust Agreement, the Trustee pays Eastern American an annual fee which increases by 3.5% per year, payable quarterly, to reimburse Eastern American for overhead expenses. The initial fee at the inception of the Trust was $210,000. The Trustee paid Eastern American $296,224, $286,208 and $276,528 for overhead expenses for 2003, 2002 and 2001 respectively. Operating cost charges included in the Statements of Distributable Income are paid to Eastern American.

Gas production attributable to the Net Profits Interests is purchased from the Trust by Eastern Marketing Corporation (Eastern Marketing), a wholly owned subsidiary of Eastern American, pursuant to a Gas Purchase Contract which effectively commenced as of January 1, 1993 and expires upon the termination of the Trust.

Pursuant to the Gas Purchase Contract, Eastern Marketing is obligated to purchase such gas production at a purchase price per Mcf equal to the greater of the Index Price, as defined below, or a Floor Price, for gas produced in any quarter during the Primary Term, which ended December 31, 1999. Effective January 1, 2000, Eastern Marketing is obligated to purchase such gas production at a purchase price per Mcf equal to the Index Price for gas produced in any quarter after the Primary Term.

The Index Price for any quarter subsequent to the Primary Term, which expired December 31, 1999, is determined solely by reference to the Variable Price component. The Variable Price for any quarter is equal to the Henry Hub Average Spot Price (as defined) per MMBtu plus $0.30 per MMBtu, multiplied by 110% to effect a fixed adjustment for Btu content. The Henry Hub Average Spot Price is defined as the price per MMBtu determined for any calendar quarter equal to the price obtained with respect to each of the three months in such quarter, in the manner specified below, and then taking the average of the prices determined for each of such three months. The price determined for any month of such quarter is equal to the average of (i) the final settlement prices per MMBtu for Henry Hub Gas Futures Contracts (as defined), as reported in *The Wall Street Journal,* for such contracts which expired in each of the five months prior to such month, (ii) the final settlement price per MMBtu for Henry Hub Gas Futures Contracts, as reported in *The Wall Street Journal,* for such contracts which expire during such month and (iii) the closing settlement prices per MMBtu of Henry Hub Gas Futures Contracts determined as of the contract settlement date for such month, as reported in *The Wall Street Journal,* for such contracts which expire in each of the six months following such month. A Henry Hub Gas Futures Contract is defined as a gas futures contract for gas to be delivered to the Henry Hub which is traded on the New York Mercantile Exchange.

Under a standby performance agreement Eastern American has agreed to make payments under the Gas Purchase Contract to the extent such payments are not made by Eastern Marketing.

6. Treasury Obligations:

The Treasury Obligations are directly owned by the Unitholders and are not part of the Trust Corpus. The Treasury Obligations are on deposit with the Trustee pursuant to the Deposit Agreement.

The high and low closing prices of the Treasury Obligations, which have a $1,000 face principal amount, as quoted in the over-the-counter market for United States Treasury Obligations, are as follows:

	High	Low
Quarter ended March 31, 2001	$ 532.30	$ 501.20
Quarter ended June 30, 2001	524.90	494.30
Quarter ended September 30, 2001	549.30	503.70
Quarter ended December 31, 2001	577.70	513.60

Quarter ended March 31, 2002	$ 548.40	$ 516.20
Quarter ended June 30, 2002	566.40	518.10
Quarter ended September 30, 2002	644.20	560.70
Quarter ended December 31, 2002	641.90	600.40
Quarter ended March 31, 2003	$ 671.20	$ 618.30
Quarter ended June 30, 2003	711.50	641.50
Quarter ended September 30, 2003	684.00	620.30
Quarter ended December 31, 2003	665.10	634.00

On December 31, 2003, 2002 and 2001, the closing price of the Treasury Obligations, as quoted on such market, was $658.60, $637.10 and $526.10, respectively.

The Trust provides Unitholders with the option to separate the related Treasury Obligation from the Trust Units. Upon exercising this option, the Unitholder receives the related Treasury obligation. As of December 31, 2003 and 2002, this option was exercised on Trust Units of 77,900 and 107,900 respectively.

7. Supplemental Reserve Information (Unaudited):

Information regarding estimates of the proved gas reserves attributable to the Trust are 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. Fixed gas prices were used during the Primary Term, which ended December 31, 1999. The gas prices used thereafter are based solely on the fourth quarter Variable gas price component.

The reserves and revenue values for the Underlying Properties transferred to the Trust were estimated from projections of reserves and revenue values attributable to the combined Eastern American and Trust interests in these properties. Reserve quantities are calculated differently for the Net Profits Interests because such interests do not entitle the Trust to a specific quantity of gas but to 90 percent of the Net Proceeds derived therefrom. Accordingly, there is no precise method of allocating estimates of the quantities of proved reserves between those held by the Trust and the interests to be retained by Eastern American. For purposes of this presentation, the proved reserves attributable to the Net Profits Interests have been proportionately reduced to reflect the future estimated costs and expenses deducted in the calculation of Net Proceeds with respect to the Net Profits Interests. The reserves presented for the Net Profits Interests reflect quantities of gas that are free of future costs or expenses. The allocation of proved reserves between the Trust and Eastern American will vary in the future as relative estimates of future gross revenues and future costs and expenses vary.

The royalty portion of the Net Profits Interests was calculated beyond the liquidation date of the Trust (May 15, 2013), even though the terms of the Trust Agreement require that the Royalty Net Profits Interest will be sold by the Trustee on or about this date and a liquidating distribution from the sales proceeds from such sale would be made to the Unitholders. The Term Net Profits Interests was limited to the 20-year period as defined by the Trust Agreement.

The following table reconciles the change in proved reserves attributable to the Trust s share of the Net Profits Interests (NPI) from January 1, 2001 to December 31, 2003:

	Royalty NPI (MMcf)	**Term NPI (MMcf)**	**Total NPI (MMcf)**
Balance, January 1, 2001	14,983	11,484	26,467
Production	(1,068)	(1,421)	(2,489)
Revisions of previous estimates	(1,011)	(222)	(1,233)
Balance, December 31, 2001	12,904	9,841	22,745
Production	(1,034)	(1,324)	(2,357)
Revisions of previous estimates	(155)	(92)	(246)
Balance, December 31, 2002	12,025	8,609	20,634
Production	(932)	(1,229)	(2,161)
Revisions of previous estimates	3,049	1,188	4,237
Balance, December 31, 2003	14,142	8,568	22,710

The Trust s share of proved developed gas reserves are as follows:

	Royalty NPI (MMcf)	**Term NPI (MMcf)**	**Total NPI (MMcf)**
December 31, 2001	12,904	9,841	22,745
December 31, 2002	12,025	8,609	20,634
December 31, 2003	14,142	8,568	22,710

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

The following is the standardized measure of discounted future net cash flows as of December 31, 2003 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 80,951	$ 49,043	$ 129,994
Future production costs	(4,420)	(2,333)	(6,754)
Future production taxes	(11,885)	(3,967)	(15,852)
Future net cash inflows	64,646	42,743	107,389
10% discount factor	(37,289)	(13,651)	(50,940)
Standardized measure of discounted future net cash flows	$ 27,357	$ 29,092	$ 56,449

The following is the standardized measure of discounted future net cash flows as of December 31, 2002 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 69,983	$ 44,562	$ 114,545
Future production taxes	(3,839)	(2,104)	(5,943)
Future production costs	(12,400)	(3,986)	(16,386)
Future net cash inflows	53,743	38,472	92,215
10% discount factor	(30,790)	(13,114)	(43,904)
Standardized measure of discounted future net cash flows	$ 22,953	$ 25,358	$ 48,311

The following is the standardized measure of discounted future net cash flows as of December 31, 2001 (in thousands):

	Royalty NPI	Term NPI	Total NPI
Future cash inflows	$ 61,197	$ 41,224	$ 102,421
Future production taxes	(3,334)	(1,916)	(5,249)
Future production costs	(11,924)	(4,275)	(16,199)

Future net cash inflows		45,939		35,033		80,973
10% discount factor		(25,930)		(12,614)		(38,545)
Standardized measure of discounted future net cash flows	$	20,009	$	22,419	$	42,428

Changes in Standardized Measure of Discounted Future Net Cash Flows:

The following schedule reconciles the changes during 2001, 2002 and 2003 in the standardized measure of discounted future net cash flows relating to proved reserves (in thousands):

	Royalty NPI	Term NPI	Total NPI
Standardized measure, January 1, 2001	$ 35,074	$ 39,646	$ 74,720
Net proceeds to the Trust	(6,721)	(5,125)	(11,846)
Revisions of previous estimates	(1,886)	(414)	(2,300)
Accretion of discount	3,507	3,965	7,472
Net change in price and production costs	(13,327)	(9,638)	(22,965)
Other	3,362	(6,015)	(2,653)
Standardized measure, December 31, 2001	$ 20,009	$ 22,419	$ 42,428
Net proceeds to the Trust	(4,610)	(3,300)	(7,910)
Revisions of previous estimates	(363)	(215)	(578)
Accretion of discount	2,001	2,242	4,243
Net change in price and production costs	5,650	4,054	9,704
Other	266	159	425
Standardized measure, December 31, 2002	$ 22,953	$ 25,358	$ 48,311
Net proceeds to the Trust	(7,329)	(4,440)	(11,770)
Revisions of previous estimates	7,579	2,953	10,532
Accretion of discount	2,295	2,536	4,831
Net change in price and production costs	1,601	1,065	2,666
Other	258	1,621	1,879
Standardized measure, December 31, 2003	$ 27,357	$ 29,092	$ 56,449

8. Quarterly Financial Data (Unaudited):

The following is a summary of royalty income and distributable income per unit by quarter in 2003, 2002 and 2001 (all amounts in thousands except Distributable income per unit):

2003	**Mar 31**	**June 30**	**Sept 30**	**Dec 31**	**Total**
Royalty income	$ 2,999	$ 3,645	$ 3,521	$ 3,012	$ 13,177
Distributable income	$ 2,363	$ 3,054	$ 3,014	$ 2,517	$ 10,948
Distributable income per unit	$ 0.4005	$ 0.5175	$ 0.5109	$ 0.4266	$ 1.8556

2002	**Mar 31**	**June 30**	**Sept 30**	**Dec 31**	**Total**
Royalty income	$ 1,771	$ 2,192	$ 2,449	$ 2,612	$ 9,025
Distributable income	$ 1,663	$ 1,950	$ 2,030	$ 2,166	$ 7,809
Distributable income per unit	$ 0.2819	$ 0.3305	$ 0.3440	$ 0.3671	$ 1.3235

2001	**Mar 31**	**June 30**	**Sept 30**	**Dec 31**	**Total**
Royalty income	$ 4,307	$ 3,840	$ 2,872	$ 2,241	$ 13,260
Distributable income	$ 3,726	$ 3,311	$ 2,444	$ 1,787	$ 11,268
Distributable income per unit	$ 0.6315	$ 0.5612	$ 0.4143	$ 0.3029	$ 1.9099