UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

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

or

☐ **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 1-7884

Mesa Royalty Trust
(Exact Name of Registrant as Specified in Its Charter)

Texas (State or Other Jurisdiction of Incorporation or Organization)	**74-6284806** (I.R.S. Employer Identification No.)
JPMorgan Chase Bank, Trustee **Institutional Trust Services** **700 Lavaca** **Austin, Texas** (Address of Principal Executive Offices)	**78701** (Zip Code)

Registrant's telephone number, including area code: 800-852-1422

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 ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

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

The aggregate market value of 1,863,590 Units of Beneficial Interest in Mesa Royalty Trust held by non-affiliates of the registrant at the closing sales price on June 30, 2003, of $52.35 was approximately $97,559,000.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

As of March 12, 2004, 1,863,590 Units of Beneficial Interest in Mesa Royalty Trust.

Documents Incorporated By Reference: None.

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Note Regarding Forward-Looking Statements

This Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-K are forward-looking statements. Although the Working Interest Owners have advised the Trust that they believe that the expectations reflected in the forward-looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from expectations ("Cautionary Statements") are disclosed in this Form 10-K, including without limitation in conjunction with the forward-looking statements included in this Form 10-K. A consolidated summary description of principal risk factors that could cause actual results to differ is also set forth in this Form 10-K under "Business—Principal Trust Risk Factors." All subsequent written and oral forward-looking statements attributable to the Trust or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements.

PART I

Item 1. Business.

DESCRIPTION OF THE TRUST

The Mesa Royalty Trust (the "Trust"), created under the laws of the State of Texas, maintains its offices at the office of the Trustee, JPMorgan Chase Bank (the "Trustee"), 700 Lavaca, Austin, Texas 78701. The telephone number of the Trust is 1-800-852-1422. JPMorgan Chase Bank was formerly known as The Chase Manhattan Bank and is the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association.

The Trustee does not maintain a website for filings by the Trust with the U.S. Securities and Exchange Commission ("SEC"). Electronic filings by the Trust with the SEC are available free of charge through the SEC's website at *www.sec.gov*.

The Trust was created on November 1, 1979 when Mesa Petroleum Co. conveyed to the Trust a 90% net profits overriding royalty interest (the "Royalty") in certain producing oil and gas properties located in the Hugoton field of Kansas, the San Juan Basin field of New Mexico and Colorado, and the Yellow Creek field of Wyoming (collectively, the "Royalty Properties"). Mesa Petroleum Co. was the predecessor to Mesa Limited Partnership ("MLP"), which was the predecessor to MESA Inc. On April 30, 1991, MLP sold its interests in the Royalty Properties located in the San Juan Basin field to ConocoPhillips, successor by merger to Conoco Inc. ("ConocoPhillips"). ConocoPhillips sold the portion of its interests in the San Juan Basin Royalty Properties located in Colorado to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the Colorado San Juan Basin Royalty Properties to BP Amoco Production Company ("BP Amoco"), a subsidiary of BP Amoco. Until August 7, 1997, MESA Inc. operated the Hugoton Royalty Properties through Mesa Operating Co., a wholly owned subsidiary of MESA Inc. On August 7, 1997, MESA Inc. merged with and into Pioneer Natural Resources Company ("Pioneer"), formerly a wholly owned subsidiary of MESA Inc., and Parker & Parsley Petroleum Company merged with and into Pioneer Natural Resources USA, Inc. (successor to Mesa Operating Co.), a wholly owned subsidiary of Pioneer ("PNR") (collectively, the mergers are referred to herein as the "Merger"). Subsequent to the Merger, the Hugoton Royalty Properties have been operated by PNR. The San Juan Basin Royalty Properties located in New Mexico are operated by ConocoPhillips. Substantially all of the San Juan Basin Royalty Properties located in Colorado are operated by BP Amoco. As used in this report, PNR refers to the operator of the Hugoton Royalty Properties, ConocoPhillips refers to the operator of the New Mexico San Juan Basin Royalty Properties and BP Amoco refers to the operator of the Colorado San Juan Basin Royalty Properties, unless otherwise indicated. The terms "working interest owner" and "working interest owners" generally refer to the operators of the Royalty Properties as described above, unless the context in which such terms are used indicates otherwise.

The terms of the Mesa Royalty Trust Indenture (the "Trust Indenture") provide, among other things, that: (1) the Trust cannot engage in any business or investment activity or purchase any assets; (2) the Royalty can be sold in part or in total for cash upon approval of the unitholders; (3) the Trustee can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payment of the borrowings; (4) in January, April, July and October of each year the Trustee will make quarterly distributions of cash available for distribution to the unitholders; and (5) the Trust will terminate upon the first to occur of the following events: (i) at such time as the Trust's royalty income for each of two successive years is less than $250,000 per year or (ii) a vote of the unitholders in favor of termination. Royalty income of the Trust was $9,299,034 and $4,841,115 for the years 2003 and 2002, respectively. Upon termination of the Trust, the Trustee will sell for cash all the assets held in the Trust estate and make a final distribution to unitholders of any funds remaining after all Trust liabilities have been satisfied.

Under the instrument conveying the Royalty to the Trust (the "Conveyance"), the Trust is entitled to a percentage of the Net Proceeds, as hereinafter defined, realized from the minerals as, if and when produced from the Royalty Properties. See "Description of Royalty Properties." The Conveyance provides for a monthly computation of Net Proceeds. "Net Proceeds" means the excess of Gross Proceeds, as hereinafter defined, received by the working interest owners during a particular period over operating and capital costs for such period. "Gross Proceeds" means the amount received by the working interest owners from the sale of minerals covered by the Royalty, subject to certain adjustments. Operating costs mean, generally, costs incurred on an accrual basis by the working interest owners in operating the Royalty Properties, including capital and non-capital costs. If operating and capital costs exceed Gross Proceeds for any month, the excess plus interest thereon at 120% of the prime rate of Bank of America is recovered out of future Gross Proceeds prior to the making of further payment to the Trust. The Trust, however, is generally not liable for any operating costs or other costs or liabilities attributable to the Royalty Properties or minerals produced therefrom. The Trust is not obligated to return any royalty income received in any period. The working interest owners are required to maintain books and records sufficient to determine the amounts payable under the Royalty. Additionally, in the event of a controversy between a working interest owner and any purchaser as to the correct sales price for any production, amounts received by such working interest owner and promptly deposited by it with an escrow agent are not considered to have been received by such working interest owner and therefore are not subject to being payable with respect to the Royalty until the controversy is resolved; but all amounts thereafter paid to such working interest owner by the escrow agent will be considered amounts received from the sale of production. Similarly, operating costs include any amounts a working interest owner is required to pay whether as a refund, interest or penalty to any purchaser because the amount initially received by such working interest owner as the sales price was in excess of that permitted by the terms of any applicable contract, statute, regulation, order, decree or other obligation. Within 30 days following the close of each calendar quarter, the working interest owners are required to deliver to the Trustee a statement of the computation of Net Proceeds attributable to such quarter.

The brief discussions of the Trust Indenture and the Conveyance contained herein are qualified in their entirety by reference to the Trust Indenture and the Conveyance themselves, which are exhibits to this Form 10-K and are available upon request from the Trustee.

The Royalty Properties are required to be operated by the working interest owners in accordance with reasonable and prudent business judgment and good oil and gas field practices. Each working interest owner has the right to abandon any well or lease if, in its opinion, such well or lease ceases to produce or is not capable of producing oil, gas or other minerals in commercial quantities. Each working interest owner markets the production on terms deemed by it to be the best reasonably obtainable in the circumstances. See "Contracts". The Trustee has no power or authority to exercise any control over the operation of the Royalty Properties or the marketing of production therefrom.

In 1985 the Trust Indenture was amended at a special meeting of unitholders. The effect of the amendment was an overall reduction of approximately 88.56% in the size of the Trust, distributable income and related Trust reserves, effective April 1, 1985. See Note 2 in the Notes to Financial Statements under Item 8 of this Form 10-K.

The Trust has no employees. Administrative functions of the Trust are performed by the Trustee.

DESCRIPTION OF THE UNITS

Each unit is evidenced by a transferable certificate issued by the Trustee. Each unit ranks equally for purposes of distributions and has one vote on any matter submitted to unitholders. A total of 1,863,590 units were outstanding at March 12, 2004.

Distributions

The Trustee determines for each month the amount of cash available for distribution for such month. Such amount (the "Monthly Distribution Amount") consists of the cash received from the Royalty during such month less the obligations of the Trust paid during such month, adjusted for changes made by the Trustee during such month in any cash reserves established for the payment of contingent or future obligations of the Trust. The Monthly Distribution Amount for each month is payable to unitholders of record on the monthly record date (the "Monthly Record Date"), which is the close of business on the last business day of such month or such other date as the Trustee determines is required to comply with legal or stock exchange requirements. However, to reduce the administrative expenses of the Trust, under the Trust Indenture the Trustee does not distribute cash monthly, but rather, during January, April, July and October of each year distributes to each person who was a unitholder of record on one or more of the immediately preceding three Monthly Record Dates, the Monthly Distribution Amount for the month or months that he was a unitholder of record, together with interest earned on such Monthly Distribution Amount from the Monthly Record Date to the payment date. Under the terms of the Trust Indenture, interest is earned at a rate of 1½% below the prime rate charged by JPMorgan Chase Bank (as the successor by mergers to Texas Commerce Bank National Association) or the interest rate which JPMorgan Chase Bank pays in the normal course of business on amounts placed with it, whichever is greater.

Liability of Unitholders

In regards to the unitholders, the Trustee is fully liable if the Trustee incurs any liability without ensuring that such liability will be satisfiable only out of the Trust assets (regardless of whether the assets are adequate to satisfy the liability) and in no event out of amounts distributed to, or other assets owned by, unitholders. However, under Texas law, it is unclear whether a unitholder would be jointly and severally liable for any liability of the Trust in the event that all of the following conditions were to occur: (1) the satisfaction of such liability was not by contract limited to the assets of the Trust, (2) the assets of the Trust were insufficient to discharge such liability and (3) the assets of the Trustee were insufficient to discharge such liability. Although each unitholder should weigh this potential exposure in deciding whether to retain or transfer his units, the Trustee is of the opinion that because of the passive nature of the Trust assets, the restrictions on the power of the Trustee to incur liabilities and the required financial net worth of any trustee, the imposition of any liability on a unitholder is extremely unlikely.

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 the units. Except where indicated, the discussion below describes general federal income tax considerations applicable to individuals who are citizens or residents of the United States. Accordingly, the following discussion has limited application to domestic corporations and persons subject to specialized federal income tax treatment, such as regulated investment companies and insurance companies. It is impractical to comment on all aspects of federal, state, local and foreign laws that may affect the tax consequences of the transactions contemplated hereby and of an investment in the units as they relate to the particular circumstances of every unitholder. **Each unitholder should consult its own tax advisor with respect to its particular 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). 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.

Classification of the Trust

In a technical advice memorandum dated February 26, 1982, the National Office of the Internal Revenue Service ("IRS") advised the Dallas District Director that the Trust is classifiable as a grantor trust and not as an association taxable as a corporation.

Income and Depletion

Royalty income, net of depletion and severance taxes, is treated as portfolio income, and subject to certain exceptions and transitional rules, royalty income cannot be offset by losses from passive businesses. Additionally, interest income is portfolio income. Administrative expense is an investment expense.

Generally, prior to the Revenue Reconciliation Act of 1990, the transferee of an oil and gas property could not claim percentage depletion with respect to production from the property if it was "proved" at the time of the transfer. This rule is not applicable in the case of transfers of properties after October 11, 1990. Thus, eligible unitholders that acquired units after that date are entitled to claim an allowance for percentage depletion with respect to royalty income attributable to these units to the extent that this allowance exceeds cost depletion as computed for the relevant period.

Backup Withholding

Distributions from the Trust are generally subject to backup withholding at a rate of 28% of these distributions. Backup withholding will not normally apply to distributions to a unitholder, however, unless a unitholder fails to properly provide to the Trust his taxpayer identification number or the IRS notifies the Trust that the taxpayer identification number provided by a unitholder is incorrect.

Sale of Units

Generally, except for recapture items, the sale, exchange or other disposition of a unit will result in capital gain or loss measured by the difference between the basis in the unit and the amount realized. Effective for property placed in service after December 31, 1986, the amount of gain, if any, realized upon the disposition of oil and gas property is treated as ordinary income up to the amount of intangible drilling and development costs incurred with respect to the property and depletion claimed to the extent it reduced the taxpayer's basis in the property. Under this provision, depletion attributable to a unit acquired after 1986 will be subject to recapture as ordinary income upon disposition of the unit or upon disposition of the oil and gas property to which the depletion is attributable. The balance of any gain or any loss will be capital gain or loss if the unit was held by the unitholder as a capital asset, either long-term or short-term depending on the holding period of the unit. This capital gain or loss will be long-term if a unitholder's holding period exceeded one year as of the date of sale or exchange. A long-term capital gains rate of 15% applies to most capital assets sold with a holding period of more than one year. Capital gain or loss will be short-term if the unit has not been held for more than one year at the time of disposition.

Non-U.S. Unitholders

In general, a unitholder who is a nonresident alien individual or which is a foreign corporation, each a "non-U.S. unitholder" for purposes of this discussion, will be subject to tax on the gross income produced by the Royalty at a rate equal to 30% or lower treaty rate, if applicable. This tax will be withheld by the Trustee and remitted directly to the United States Treasury. A non-U.S. unitholder may elect to treat the income from the Royalty as effectively connected with the conduct of a United States trade or business under provisions of the Internal Revenue Code of 1986, as amended or pursuant to any similar provisions of applicable treaties. Upon making this election a non-U.S. unitholder is entitled to claim all deductions with respect to that income, but he must file a United States federal income tax return to claim these deductions. This election once made is irrevocable unless an applicable treaty allows the election to be made annually.

The Internal Revenue Code and the Treasury Regulations thereunder treat the publicly traded Trust as if it were a United States real property holding corporation. Accordingly, non-U.S. unitholders owning greater than five percent of the outstanding units are subject to United States federal income tax on the gain on the disposition of their units. Non-U.S. unitholders owning less than five percent of the outstanding units are not subject to United States federal income tax on the gain on the disposition of their units.

Federal income taxation of a non-U.S. unitholder is a highly complex matter which may be affected by many other considerations. Therefore, each non-U.S. unitholder should consult with his own tax adviser as to the advisability of its ownership of units.

Tax-Exempt Organizations

The Royalty and interest income should not be unrelated business taxable income so long as, generally, a unitholder did not incur debt to acquire a unit or otherwise incur or maintain a debt that would not have been incurred or maintained if the unit had not been acquired. Legislative proposals have been made from time to time which, if adopted, would result in the treatment of Royalty income as unrelated business income. Tax-exempt unitholders should consult their own advisors with respect to the treatment of royalty income.

DESCRIPTION OF ROYALTY PROPERTIES

Producing Acreage and Wells as of December 31, 2003

	Producing Acres(1)		Producing Gas Wells(1)	
	Gross	Net	Gross	Net
Hugoton Area (Kansas)	99,654	99,413	466	465.5
San Juan Basin (Northwestern New Mexico and Southwestern Colorado)	40,716	31,328	1,237	466
Total	140,370	130,741	1,703	931.5

(1) The Trust does not have a working interest in the producing acres and producing gas wells. The gross and net amounts in the table above represent gross and net amounts attributable to the working interest owners and are the basis for the Gross Proceeds amounts discussed under "Description of the Trust".

Hugoton

The principal property interest conveyed to the Trust accounts for approximately 36% of the Trust's reserves and was carved out of PNR's working interest in 104,437 net producing acres in the Hugoton field. The life of the field is expected to extend beyond the year 2020.

The gas produced from the Hugoton properties is available for sale on the spot market. See "Contracts". Since the Hugoton field gas is sold in the intrastate and interstate markets, it is subject to state and federal laws and regulations. The Kansas Corporation Commission (the "KCC") is the state regulatory agency responsible for setting field market demand (gas allowables), prorating production between wells and other related matters. Hugoton field gas is also subject to the rules and regulations of the Federal Energy Regulatory Commission (the "FERC"). See "Regulation and Prices".

San Juan Basin

The Trust's interest in the San Juan Basin was conveyed from PNR's working interest in 31,328 net producing acres in northwestern New Mexico and southwestern Colorado. The San Juan Basin-New Mexico reserves represent approximately 64% of the Trust's reserves. Substantially all of the natural gas produced from the San Juan Basin is currently being sold on the spot market. PNR completed the sale of its underlying interest in the San Juan Basin Royalty Properties to ConocoPhillips on April 30, 1991.

ConocoPhillips subsequently sold its underlying interest in the Colorado portion of the San Juan Basin Royalty Properties to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the Colorado San Juan Basin Royalty Properties to BP Amoco. See "—Description of the Trust" under Item 1 of this Form 10-K. The San Juan Basin Royalty Properties located in Colorado account for less than 5% of the Trust's reserves.

San Juan Basin Fruitland Coal Drilling

In April 1990, the working interest owner began drilling for coalbed methane gas in the Fruitland Coal formation of the San Juan Basin. The Fruitland Coal formation has been identified as one of the most prolific sources of U.S. coalbed methane reserves. The Trust owns an interest in 26,700 gross acres and 25,400 net acres with Fruitland Coal potential. The working interest owner has advised the Trust that, as of December 31, 2003, the working interest owner had drilled on Trust properties 50 (29.3 net) Fruitland Coal wells, all of which are operated by the working interest owner. Of the wells drilled in the unit, 49 (34.8 net) are currently producing at a combined rate of 35 (16.1 net) MMcf per day.

The gas that is currently being produced from these wells is being sold on the spot market, although the working interest owner has advised the Trust that it will also consider selling some of the gas produced from these wells pursuant to longer term contracts at spot market prices.

Aggregate drilling and completion costs for the entire Fruitland Coal development program were approximately $18.4 million. The Trust's share of the total expenditures was approximately $2.4 million. The Trust's share of the cost of drilling and completing the Fruitland Coal wells was subject to recovery by the working interest owner on a state-by-state basis before distributions were made from the San Juan Basin Royalty. In December 1992, after recovery by the working interest owner of the costs of the Fruitland Coal drilling in New Mexico, distributions from the New Mexico portion of the San Juan Basin Royalty resumed. No distributions related to the Colorado portion of the San Juan Basin Royalty have been made since 1990, as the costs of the Fruitland Coal drilling in Colorado have not yet been recovered. The San Juan Basin development drilling program had no effect on Royalty income or distributions relating to the Hugoton Royalty.

Reserves

A study of the proved oil and gas reserves attributable to the Hugoton Royalty as of December 31, 2003 has been made by PNR. The following letter relating to the "Reserves and Revenue as of December 31, 2003 From Certain Properties Owned by Mesa Royalty Trust" (the "Hugoton Reserve Report") summarizes such reserve study. References to the reserves of the Trust and the future net revenue and present worth attributable to the Trust interest in the Hugoton Reserve Report refer to the Trust's interest in the Hugoton Royalty Properties. The Hugoton Reserve Report reflects estimated reserve quantities and future net revenue in a manner which is based upon a month of production without regard to time of receipt by the Trust and which differs from the manner in which the Trust recognizes and accounts for its royalty income.

A study of the proved oil and gas reserves attributable to the New Mexico portion of the San Juan Basin Royalty as of December 31, 2003 has been made by ConocoPhillips, the working interest owner of such properties. The ConocoPhillips Reserve Report (together with the PNR Reserve Report, the "Reserve Reports") beginning on page 11 regarding such properties reflects estimated reserve quantities.

Proved oil and gas reserves attributable to the Colorado portion of the San Juan Basin Royalty have been omitted from the Trust's reserve disclosures included in this Form 10-K, as they represent less than 5% of the Trust's total reserves and future net revenues.

For further information regarding the Net Overriding Royalty Interest, the Basis of Accounting for the Trust, and Reserves, see Notes 2, 3 and 7, respectively, in the Notes to Financial Statements under Item 8 of this Form 10-K.

Monday, March 08, 2004

MESA Royalty Trust
JP Morgan Chase (as Trustee)
700 Lavaca Street, 5^{th} Floor
Austin, TX 78701-3102

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2003 of the extent and value of the proved natural gas liquids, natural gas and helium reserves of certain properties owned by the Mesa Royalty Trust, hereinafter referred to as the "Trust." The interest appraised consists of a 10.29282% (percent) net profits overriding royalty interest in certain properties administered by Pioneer Natural Resources USA, Inc., hereinafter referred to as "Pioneer." These properties are located in the Kansas Hugoton and Panoma-Council Grove fields in Kansas. Pioneer is 100 percent owned by Pioneer Natural Resources Company, the successor to Mesa Limited Partnership.

The reserve estimates are based on a detailed study of the Trust's properties. The method or combination of methods used in the study of each reservoir was tempered by experience in the area, consideration of the state of development of the reservoir, and the quality and completeness of basic data.

Reserves in this report are expressed as gross reserves and net reserves. Gross reserves are defined as the total estimated petroleum hydrocarbons remaining to be produced from the properties subsequent to December 31, 2003. Net reserves are defined as that portion of the gross reserves attributable to the Trust interest after deducting royalties and other interests owned by others.

Values shown herein are expressed in terms of future net revenue, future net cashflow and present worth. Future net revenue is that revenue which will accrue to the appraised interests from the production and sale of the estimated net reserves. Future net cashflow is calculated by deducting estimated production taxes, ad valorem taxes, lease operating expenses, and capital costs from the future net revenue. Future income tax expenses were not taken into account in the preparation of these estimates. Present worth is defined as future net revenue discounted at a specified arbitrary discount rate compounded monthly over the expected period of realization. In this report, present worth values are reported using a discount rate of 10% (percent).

Reserve and revenue values shown in this report were estimated from projections of reserves and revenue attributable to the combined Pioneer and Trust interests (Combined Interest) in these properties. To calculate the net profits, the future net revenue for the aggregate of the Combined Interest in the subject properties was reduced by an overhead charge and by the deficit balance as described below if any. In addition, because the net profits interest does not participate in plant and gathering expenses, a portion of the net revenue attributable to the plant interests was excluded from this calculation; the excluded portion is 35 percent of the plant revenue less 100 percent of the plant and gathering expenses. When the adjusted net revenue resulting from this calculation was greater than zero, it was multiplied by the factor of 10.29282% (percent) to arrive at the future net revenue of the Trust. If the adjusted revenue for the period was negative, the trust revenue was set to zero and interest was charged on the deficit balance. The beginning deficit balance as of December 31, 2003, was zero and no deficit is estimated for the life of the properties.

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While estimates of reserves attributable to the Trust are shown in order to comply with requirements of the SEC, this is no precise method of allocating estimates of physical quantities of reserves between the working interest owners and the Trust. The net profits overriding royalty interest is not a working interest and the Trust does not own and is not entitled to receive any specific volume of reserves from the Trust. Reserve quantities in the previously mentioned reserve studies have been allocated based on the method referenced in the Reserve Reports. The quantities of reserves attributable to the Trust will be affected by future changes in various economic factors utilized in estimating future gross and net revenues from the Trust Properties. Therefore, the estimates of reserves set forth in the Reserve Reports are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest.

Estimates of reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information becomes available. Not only are such reserve and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgmental factors in interpreting such information.

The development status shown herein represents the status applicable on December 31, 2003. In our preparation of the study, data available from wells drilled on the appraised properties through December 31, 2003 were used in estimating gross ultimate recovery. Gross production estimated to December 31, 2003 was deducted from gross ultimate recovery to arrive at the estimates of gross reserves as of December 31, 2003. In these fields, this required that the production rates be estimated for up to three months, since production data for certain properties were available only through September 2003.

Petroleum reserves included in this report are classified as proved and are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analysis, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs as of the date the estimate is made. This included consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

Proved—Reserves that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data. Commercial productivity has been established by actual production, successful testing, or in certain cases by favorable core analyses and electrical-log interpretation when the producing characteristics of the formation are known from nearby fields. Volumetrically, the structure, areal extent, volume, and characteristics of the reservoir are well defined by a reasonable interpretation of adequate subsurface well control and by known continuity of hydrocarbon-saturated material above known fluid contacts, if any, or above the lowest known structural occurrence of hydrocarbons.

Developed—Reserves that are recoverable from existing wells with current operating methods and expenses. Developed reserves include both producing and non-producing reserves. Estimates of producing reserves assume recovery by existing wells producing from present completion intervals with normal operating methods and expenses. Developed non-producing reserves are in reservoirs behind the casing or at minor depths below the producing zone and are considered proved by production from other wells in the field, by successful drill-stem tests, or by core analysis from the particular zones. Non-producing reserves require only moderate expense to be brought into production.

Undeveloped—Reserves that are recoverable from additional wells yet to be drilled. Undeveloped reserves are those considered proved for production by reasonable geological interpretation of adequate subsurface control in reservoirs that are producing or proved by other wells but are not recoverable from existing wells. This classification of reserves requires drilling of additional wells, major deepening of existing wells, or installation of enhanced recovery or other facilities.

Helium reserves were classified using the same standards as those described in the foregoing definitions of petroleum reserves. Since it is mixed in and produced with the natural gas reserves, the term gas as used herein applies to both gases, where appropriate, and the term natural gas is used to refer to hydrocarbon gas.

Estimates of the net proved reserves attributable to the Trust, as of December 31, 2003, are as follows:

TOTAL PROVED RESERVES:	
Natural Gas (Mcf)	13,096,583
Helium (Mcf)	37,344
Natural Gas Liquids (bbl)	595,378
PROVED DEVELOPED RESERVES	
Natural Gas (Mcf)	13,096,583
Helium (Mcf)	37,344
Natural Gas Liquids (bbl)	595,378

Proved natural gas liquid reserves and helium reserves are included herein for the Satanta plant, which was completed and placed on stream in the Hugoton field in Kansas during late 1993.

Future oil and gas producing rates estimated for this report are based on production rates considering the most recent figures available or, in certain cases, are based on estimates. The rates used for future production are within the capacity of the well or reservoir to produce.

Pioneer is continuing to upgrade the well gathering system, which improves deliverability of the wells. This increase in deliverability and the associated costs have been incorporated in the estimates included herein.

Gas volumes shown herein are expressed at standard conditions of 60 degrees Fahrenheit and at 14.65 pounds per square inch absolute. Gross volumes are reported as wet gas and the net volumes are reported as processed hydrocarbon sales; however, neither the gross or net volumes were reduced for plant fuel usage. The value of this fuel is deducted as part of the plant operating costs.

Revenue values in this report were estimated using current prices and costs. Future prices were estimated using guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board.

The assumptions used for estimating future prices and costs are as follows:

- Natural Gas Prices—Gas prices were held constant for the life of the properties.
- Natural Gas Liquids and Helium Prices—Natural gas liquids and helium prices were held constant for the life of the properties.
- Operating and Capital Costs—Estimates of operating costs based on current costs were used for the life of the properties with no increase in the future based on inflation. Future capital expenditures were estimated using 2003 values and were not adjusted for inflation.

The estimated future net revenue, future net cashflow and present worth discounted at 10% (percent) attributable to the Trust Interest for the life of the Trust is as follows.

TRUST INTEREST:

Future Net Revenue ($)[1]	127,008,680
Future Lease Operating Expenses ($)	18,093,648
Future Net Production Taxes ($)	2,822,877
Future Net Ad Valorem Taxes ($)	5,179,066
Future Net Overhead Expense ($)	11,453,719
Future Capital Expenditures ($)	0
Future Net Cashflow ($) 89,459,368	
Present Worth at 10 Percent ($)[1]	38,752,901

1. Future income tax expenses were not taken into account in the preparation of these estimates. Approximately 1 percent of the present worth is estimated to come from helium sales.

In our opinion, the information relating to the estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 10-13, 15 and 30(a)-(b) of Statement of Financial Accounting Standards No. 69 (November 1982) of the Financial Accounting Standards Board and Rules 4-1 0(a)(1)-(13) of Regulation S-X and Rule 302(b) of Regulation S-K of the Securities and Exchange Commission; provided, however, (I) future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein and (II) minor amounts of revenue from helium produced with the natural gas are included herein.

To the extent the above enumerated rules, regulations, and statements require determinations of an accounting or legal nature or information beyond the scope of this report, we are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefore.

Submitted,

Paul McDonald

Paul McDonald
Vice President Domestic Reservoir Engineering

CONOCOPHILLIPS INC.

LETTER REPORT

dated

MARCH 5, 2004

on

RESERVES and REVENUE

as of

DECEMBER 31, 2003

from

CERTAIN PROPERTIES

owned by

MESA ROYALTY TRUST

ConocoPhillips

Randall L. Darr
Manager, Reserves
Reservoir Technology Center
Upstream Technology

P.O. Box 2197
Houston, Texas 77252
(281) 293-1404

March 5, 2004

Mesa Royalty Trust
JPMorgan Chase Bank
700 Lavaca, 2nd Floor
Austin, TX 78701-3102

Re: **Mesa Royalty Trust Reserves as of December 31, 2003**
San Juan Basin Properties, New Mexico

Gentlemen:

Pursuant to your request, estimates have been prepared as of December 31, 2003 of the extent and value of proved natural gas, condensate, and natural gas liquid reserves of certain properties owned by the Mesa Royalty Trust, hereinafter referred to as "MRT". The MRT interest appraised consists of a 10.29282 percent net royalty interest in certain San Juan Basin properties administered by ConocoPhillips.

Reserves in this report are expressed as ConocoPhillips net reserves and MRT net reserves. ConocoPhillips net reserves are defined as ConocoPhillips' net share of estimated petroleum hydrocarbons remaining to be produced from the properties after December 31, 2003. MRT net reserves are defined as that portion of the ConocoPhillips net reserves attributable to the interest owned by MRT.

Values shown herein are expressed in terms of future revenue, future cash flow, and present worth. Future revenue is that revenue which will accrue from production and sale of the estimated net reserves. Future cash flow is calculated by deducting estimated production and ad valorem taxes, operating and transportation expenses, capital costs, and abandonment costs from the future revenue. Federal income taxes are not taken into account in the preparation of these estimates. Present worth is defined as future cash flow discounted at a specified discount rate compounded monthly over the expected period of realization. A discount rate of 10 percent is used in this report.

Reserves attributable to the MRT interest are calculated by allocating to MRT a portion of the ConocoPhillips net reserves based on future cash flow. Because reserves volumes are estimated using future cash flow, a change in prices or costs will result in changes of reserves. Therefore, the MRT net reserves will vary if different price and cost assumptions are used.

Petroleum reserves included in this report are classified as proved and judged to be economically producible in future years from known reservoirs under existing economic and operating conditions. Total proved reserves are the sum of developed and undeveloped reserves. Proved developed reserves are those recoverable from existing wells with current operating methods and expenses, and thus require little or no capital expenditure to produce. Proved undeveloped reserves are those that require major capital expenditures for new wells and/or facilities. Estimates of the MRT net reserves and production as of December 31, 2003 are tabulated below. The MRT net reserves and production reported for the previous year are included for comparison.

MRT Net Proved Reserves San Juan Basin Developed + Undeveloped	Conventional Reservoirs		Fruitland Coal Reservoirs		Total All Reservoirs	
	12/31/02	12/31/03	12/31/02	12/31/03	12/31/02	12/31/03
Natural Gas, MMscf	16,416	17,810	906	498	17,322	18,307
Condensate, Mbbl	79	80	0	0	79	80
Natural Gas Liquids, Mbbl	1,056	1,865	0	0	1,056	1,865

MRT Net Proved Reserves San Juan Basin Developed Only	Conventional Reservoirs		Fruitland Coal Reservoirs		Total All Reservoirs	
	12/31/02	12/31/03	12/31/02	12/31/03	12/31/02	12/31/03
Natural Gas, MMscf	15,657	17,323	906	498	16,563	17,820
Condensate, Mbbl	78	79	0	0	78	79
Natural Gas Liquids, Mbbl	1,007	1,813	0	0	1,007	1,813

Both MRT Proved Developed and Proved Undeveloped reserves increased in 2003 due to improvements in product price. Many of the Proved Undeveloped Reserves will be accessed in future years through an active development and re-completion program. The reserves values reflect natural gas shrinkage of 13.237 percent for conventional gas reservoirs due to processing and plant fuel use, and an average net back to producing properties of 61 percent of recovered natural gas liquids. The Fruitland Coal reservoir has dry gas (no natural gas liquids) and therefore is not subject to shrinkage due to liquids extraction.

Product prices and operating costs used for yearend 2003 are shown in the table below, along with those used last year for comparison. Prices and operating costs are held constant over the life of the properties. The December 2003 product prices are higher than the December 2002 product prices.

Product Prices	December 2002	December 2003
Conventional Nat. Gas, $/Mscf	3.99	4.69
Coal Natural Gas, $/Mscf	3.95	4.64
Condensate, $/Bbl	27.50	28.01
Natural Gas Liquids, $/Bbl	18.50	21.65

Revenue and cash flow values in this report are based on product prices for the San Juan Basin effective on December 31, 2003. The gas price excludes a transportation expense of $0.54 per Mcf for conventional gas and $0.74 per Mcf for Fruitland Coal gas. The price also excludes combined production and ad valorem tax rates of 9.8 percent and 8.1 percent of revenue for conventional and Fruitland Coal gas, respectively. These taxes compare with the 2002 rates of 10.4 percent for conventional gas and 8.9 percent for Fruitland Coal. The taxes and transportation expenses are also excluded from the annual per completion operating costs tabulated below.

	Net Active Completions		Operating Costs ($/compl/year)	
Operating Costs	**12/31/02**	**12/31/03**	**12/31/02**	**12/31/03**
Conventional Gas	498	712	13,800	17,936
Fruitland Coal Gas	34	120	69,100	67,743

A summary of estimated future revenue, taxes, costs, cash flow, and present worth attributable to ConocoPhillips' net reserves as of December 31, 2003 is shown in the table below. The 2002 numbers are included for comparison. All costs are yearend 2003 estimates and are not adjusted for inflation. Cash flow and present worth are reported on a before federal income tax (BFIT) basis.

	Conventional Reservoirs		Fruitland Coal Reservoirs		Total All Reservoirs	
ConocoPhillips Net Interest San Juan Basin	**12/31/02**	**12/31/03**	**12/31/02**	**12/31/03**	**12/31/02**	**12/31/03**
Future Revenue, M$	1,307,807	1,715,605	74,209	65,797	1,382,016	1,781,402
Production & Ad Valorem Taxes, M$	136,533	167,555	6,578	5,349	143,111	172,904
Operating & Transportation Costs, M$	301,948	300,077	32,023	28,477	333,971	328,554
Abandonment Costs, M$	2,649	4,157	169	334	2,818	4,491
Capital Costs, M$	19,498	18,323	689	9,197	20,187	27,520
Future BFIT Cash Flow, M$	847,179	1,225,493	34,750	22,440	881,929	1,247,933
Deficit Balance, M$	0	0	0	0	0	0
Future BFIT Cash Flow Subject to MRT Interest, M$	847,179	1,225,493	34,750	22,440	881,929	1,247,933
Present Worth @ 10%, M$	354,572	503,209	22,962	11,806	377,534	515,015

ConocoPhillips' future revenues, BFIT cash flows, and present worth are higher in 2003 due to the increased product prices.

Capital costs are associated with projects required to maintain existing production of developed reserves and to produce undeveloped proved reserves. The relatively unchanged capital costs for the conventional reservoir reflect a consistent inventory of proved undeveloped reserves and the increased capital costs for the Fruitland coal reservoir reflects an increase in focus to drill 160-acre Fruitland coal infill wells.

A summary of estimated future cash flow and present worth attributable to the MRT interest as of December 31, 2003 is tabulated below, along with what was reported last year for comparison.

MRT Interest (10.29282%) San Juan Basin	Conventional Reservoirs		Fruitland Coal Reservoirs		Total All Reservoirs	
	12/31/02	12/31/03	12/31/02	12/31/03	12/31/02	12/31/03
Future BFIT Cash Flow, M$	87,199	126,138	3,577	2,310	90,776	128,448
Present Worth @ 10%, M$	36,495	51,794	2,363	1,215	38,858	53,009

Compared to last year, future BFIT cash flow and present worth are higher for the conventional gas and the Fruitland Coal gas due to an increase in product prices.

The information relating to estimated proved reserves (natural gas, condensate, and natural gas liquids), estimated future revenue from proved reserves, and present worth of cash flow contained in this report has been prepared in accordance with regulations of the Financial Accounting Standards Board and Securities and Exchange Commission.

Sincerely,

Randall Darr

Randall Darr

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The preceding reserve data in the Reserve Reports represent estimates only and should not be construed as being exact. Reserve assessment is a subjective process of estimating the recovery from underground accumulations of gas and oil that cannot be measured in an exact way, and estimates of other persons might differ materially from those of PNR and ConocoPhillips. Accordingly, reserve estimates are often different from the quantities of hydrocarbons that are ultimately recovered.

While estimates of reserves attributable to the Royalty are shown in order to comply with requirements of the SEC, there is no precise method of allocating estimates of physical quantities of reserves between the working interest owners and the Trust, since the Royalty is not a working interest and the Trust does not own and is not entitled to receive any specific volume of reserves from the Royalty. Reserve quantities in the previously mentioned reserve studies have been allocated based on the method referenced in the Reserve Reports. The quantities of reserves attributable to the Trust will be affected by future changes in various economic factors utilized in estimating future gross and net revenues from the Royalty Properties. Therefore, the estimates of reserves set forth in the Reserve Reports are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest.

Moreover, the discounted present values in the Reserve Reports should not be construed as the current market value of the estimated gas and oil reserves attributable to the Royalty Properties or the costs that would be incurred to obtain equivalent reserves, since a market value determination would include many additional factors. In accordance with applicable regulations of the SEC, estimated future net revenues were based on current prices and costs, whereas actual future prices and costs may be materially greater or less. The estimates in the Reserve Reports use market prices as of the end of the year. These prices (having a weighted average of $5.69 per Mcf for Hugoton properties and $4.69 per Mcf for San Juan Basin properties as of December 31, 2003) were held constant over the estimated life of the Royalty Properties. These prices were influenced by seasonal demand for natural gas and may not be the most appropriate or representative prices to use for estimating future revenues or related reserve data. The average price of natural gas from the Royalty Properties during 2003 was $4.72 per Mcf, representing a combination of contract prices and spot market prices.

The future net revenues shown by the Reserve Reports have not been reduced for costs and expenses of the Trust, which are expected to approximate $50,000 annually. The costs and expenses of the Trust may increase in future years, depending on the amount of Royalty income, increases in accounting, engineering, legal and other professional fees and other factors.

Income, Production and Average Prices

Reference is made to "Summary of Royalty Income, Production and Average Prices" under Item 7 of this Form 10-K for information concerning income, production and prices with respect to the Royalty.

CONTRACTS

Hugoton Field

Natural gas and natural gas liquids produced by PNR from the Hugoton field and attributable to the Royalty accounted for approximately 57% of the Royalty income of the Trust during 2003.

PNR has advised the Trust that since June 1, 1995 natural gas produced from the Hugoton field has generally been sold under short-term and multi-month contracts at market clearing prices to multiple purchasers. During 2003, these purchasers included Tenaska, Greely Gas, Oneok Gas Marketing, Inc., and Anadarko Energy Services, Inc. PNR has advised the Trust that it expects to continue to market gas production from the Hugoton field under short-term and multi-month contracts. Overall market prices received for natural gas from Hugoton Royalty Properties were higher in the year-ended December 31, 2003 as compared to the year-ended December 31, 2002.

In June 1994, PNR entered into a gas transportation agreement (the "Gas Transportation Agreement") with Western Resources, Inc. ("WRI") for a primary term of five years commencing June 1, 1995. This contract has been continued in effect on a year-to-year basis since June 1, 2001. PNR has extended the contract to June 1, 2004. Pursuant to the Gas Transportation Agreement, WRI agreed to compress and transport up to 160 MMcf per day of gas and redeliver such gas to PNR at the inlet of PNR's Satanta Plant. PNR agreed to pay WRI a fee of $0.06 per Mcf escalating 4% annually as of June 1, 1996. This Gas Transportation Agreement has been assigned to Kansas Gas Service ("Oneok").

Allowable rates of production in the Hugoton field are set by the KCC based on the level of market demand. The Hugoton field allowable for the period October 1, 2003 through March 31, 2004, was 119.1 billion cubic feet of gas, compared with 134.7 billion cubic feet of gas during the same period last year.

San Juan Basin

Natural gas produced from the San Juan Basin field and attributable to the Royalty accounted for approximately 43% of the Royalty income of the Trust during 2003. The majority of gas produced from the San Juan Basin is now being sold on the spot market.

Market for Natural Gas

The amount of cash distributions by the Trust is dependent on, among other things, the sales prices for natural gas produced from the Royalty Properties and the quantities of gas sold. The natural gas industry in the United States during the 1990's was affected generally by a surplus in natural gas deliverability compared to demand. Demand for gas declined during this period due to a number of factors including the implementation of energy conservation programs, a shift in economic activity away from energy intensive industries and competition from alternative fuel sources such as residual fuel oil, coal and nuclear energy. In late 2000 and in early 2001, demand for natural gas increased as a result of the increase in clean burning natural gas fired power generation, the increase in the usage of electrical power fueled by the expanding U.S. economy and a return to seasonally cold winters. Average annual wellhead prices generally increased from $1.55 per Mcf in 1995 to $2.32 per Mcf in 1997, decreased to $1.96 per Mcf in 1998, increased to $3.69 per Mcf in 2000, increased to $4.02 per Mcf in 2001, decreased to $2.95 per Mcf in 2002, then increased to $5.09 per Mcf in 2003 according to Natural Gas Monthly published by the Energy Information Administration of the Department of Energy.

Due to the seasonal nature of demand for natural gas and its effects on sales prices and production volumes, the amounts of cash distributions by the Trust may vary substantially on a seasonal basis. Generally, production volumes and prices are higher during the first and fourth quarters of each calendar year due primarily to peak demand in these periods. Because of the time lag between the date on which the working interest owners receive payment for production from the Royalty Properties and the date on which distributions are made to unitholders, the seasonality that generally affects production volumes and prices is generally reflected in distributions to unitholders in later periods.

Competition

The production and sale of gas in the Hugoton field and San Juan Basin areas is highly competitive, and the working interest owners' competitors in these areas include the major oil and gas companies, independent oil and gas companies, and individual producers and operators. There are numerous producers in the Hugoton field and the San Juan Basin areas. The working interest owners have advised the Trust that they believe that their competitive position in their respective areas is affected by price, contract terms and quality of service. PNR has also advised the Trust that it believes that its competitive position in the Hugoton field is enhanced by virtue of its substantial holdings and ownership and control of its wells, gathering systems and processing plant. Market conditions in the San Juan Basin are negatively affected by the fact that most of the gas produced from such areas is transported on one of only two major pipelines, and the transportation of such gas is generally controlled by a small number of distribution companies.

REGULATION AND PRICES

General

The production and sale of natural gas from the Royalty Properties are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and gas production operations and economics are, or in the past have been, affected by price controls, taxes, conservation, safety, environmental and other laws relating to the petroleum industry, by changes in such laws and by constantly changing administrative regulations.

FERC Regulation

In recent years, the FERC has required interstate pipeline companies to "unbundle" their services. To the extent a pipeline company or its sales affiliate makes gas sales as a merchant in the future, it does so pursuant to private contracts in direct competition with all other sellers, such as the working interest owners. In recent years, the FERC also has pursued a number of other policy initiatives which could significantly affect the marketing of natural gas. Several of these initiatives are intended to enhance competition in natural gas markets, although some, such as "spindowns" of gathering assets, may have the adverse effect of increasing the cost of doing business on some in the industry. Generally, the FERC retained its existing tests for determining the jurisdictional status of offshore facilities, but eased the application of its jurisdiction over facilities in water depths of 200 meters or more. On February 9, 2000, the FERC issued Order No. 637, which permits, and in some cases requires, interstate natural gas pipelines to make certain changes to the nature of interstate transportation services. In Order No. 637-A, the FERC made certain clarifying adjustments to the regulations promulgated in Order No. 637. In Order No. 637-B, the FERC denied all further requests for rehearing. Order Nos. 637, *et seq.* currently are pending judicial review. In addition to the changes implemented through Order No. 637, the FERC has stated that it will institute a review of its regulatory model in light of the changes in the natural gas industry. As to all of these recent FERC initiatives, the working interest owners have advised the Trust that the on-going, or, in some instances, preliminary evolving nature of these regulatory initiatives makes it impossible at this time to predict their ultimate impact on the prices, markets or terms of sale of natural gas related to the Trust.

State and Other Regulation

All of the jurisdictions in which the Trust has an interest in producing oil and gas properties have statutory provisions regulating the production and sale of crude oil and natural gas. The regulations often require permits for the drilling of wells but extend also to the spacing of wells, the prevention of waste of oil and gas resources, the rate of production, prevention and clean-up of pollution and other matters. See "Contracts—Hugoton Field" for a discussion of PNR's allowables in the Hugoton Royalty Properties.

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take requirements. For example, Oklahoma and Kansas have enacted a prohibition against discriminatory gathering rates. In addition, certain Texas regulatory officials have expressed interest in evaluating similar rules, but to date no actions have been taken towards regulatory gathering rates in the state.

Natural gas pipeline facilities used for the transportation of natural gas in interstate commerce are subject to Federal minimum safety requirements. These requirements, however, are not applicable to, *inter alia*,: (1) onshore gathering facilities outside: (i) the limits of any incorporated or unincorporated city, town, or village; and (ii) any designated residential or commercial area; or (2) pipeline facilities on the Outer Continental Shelf ("OCS") upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator. *See* 49 C.F.R. § 192.1(b). We are informed that the Royalty Properties are located in the Hugoton field in Kansas, the San Juan Basin in New Mexico and Colorado, and the Yellow Creek field of Wyoming. Furthermore, those states have adopted the Federal minimum safety requirements for intrastate pipelines within their borders. The standards governing pipeline safety have undergone recent changes and it is possible that future changes in the regulations and statutes may occur which may increase the stringency of the standards or expand the applicability of the standards to facilities not currently covered.

Environmental Matters

The working interest owners' operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment, including the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA" or "Superfund"), the Solid Waste Disposal Act, the Clean Air Act, and the Federal Water Pollution Control Act. These laws and regulations, including their state counterparts, can impose liability upon the lessee under a lease for the cost of cleanup of discharged materials resulting from a lessee's operations or can subject the lessee to liability for damages to natural resources. Violations of environmental laws, regulations, or permits can result in civil and criminal penalties as well as potential injunctions curtailing operations in affected areas and restrictions on the injection of liquids into the subsurface that may contaminate groundwater. The working interest owners have advised the Trust that they maintain insurance for costs of cleanup operations, but they are not fully insured against all such risks. A serious release of regulated materials could result in the U.S. Department of the Interior requiring lessees under federal leases to suspend or cease operations in the affected area. In addition, the recent trend toward stricter standards and regulations in environmental legislation is likely to continue. For example, from time to time legislation has been proposed in Congress that would reclassify certain oil and gas production wastes as "hazardous wastes" which would subject the handling, disposal and cleanup of these wastes to more stringent requirements and result in increased operating costs for the Royalty Properties, as well as the oil and gas industry in general. State initiatives to further regulate the disposal of oil and gas wastes are also pending in certain states, and these initiatives could have a similar impact on the Royalty Properties.

The working interest owners have advised the Trust that they are not involved in any administrative or judicial proceedings relating to the Royalty Properties arising under federal, state or local environmental protection laws and regulations or which would have a material adverse effect on the working interest owners' financial position or results of operations.

PRINCIPAL TRUST RISK FACTORS

Although risk factors are described elsewhere in this Form 10-K together with specific Cautionary Statements, the following is a summary of the principal risks associated with an investment in units in the Trust.

Natural gas prices fluctuate due to a number of factors, and lower prices will reduce net proceeds available to the Trust and distributions to Trust unitholders.

The Trust's quarterly distributions are highly dependent upon the prices realized from the sale of natural gas. Natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and the working interest owners. Factors that contribute to price fluctuation include, among others:

- political conditions worldwide, in particular political disruption, war or other armed conflicts in oil producing regions;
- worldwide economic conditions;
- weather conditions;
- the supply and price of foreign natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities; and
- the effect of worldwide energy conservation measures.

Moreover, government regulations, such as regulation of natural gas transportation and price controls, can affect product prices in the long term.

Lower natural gas prices may reduce the amount of natural gas that is economic to produce and reduce net profits available to the Trust. The volatility of energy prices reduces the predictability of future cash distributions to unitholders. Substantially all of the natural gas and natural gas liquids produced from the Royalty Properties is being sold under short-term or multi-month contracts at market clearing prices or on the spot market.

Increased production and development costs for the Royalty will result in decreased Trust distributions.

Production and development costs attributable to the Royalty are deducted in the calculation of the Trust's share of net proceeds. Accordingly, higher or lower production and development costs, without concurrent increases in revenues, directly decrease or increase the amount received by the Trust for the Royalty.

If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive net proceeds for those properties until future proceeds from production exceed the total of the excess costs plus accrued interest during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs.

Trust reserve estimates depend on many assumptions that may prove to be inaccurate, which could cause both estimated reserves and estimated future revenues to be too high.

The value of the units of beneficial interest of the Trust depends upon, among other things, the amount of reserves attributable to the Royalty and the estimated future value of the reserves. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation; and
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures.

Changes in these assumptions can materially change reserve estimates.

The reserve quantities attributable to the Royalty and revenues are based on estimates of reserves and revenues for the underlying properties. The method of allocating a portion of those reserves to the Trust is complicated because the Trust holds an interest in the Royalty and does not own a specific percentage of the natural gas reserves.

Operating risks for the working interest owners' interests in the Royalty Properties can adversely affect Trust distributions.

The occurrence of drilling, production or transportation accidents and other natural disasters at any of the Royalty Properties will reduce Trust distributions by the amount of uninsured costs. These occurrences include blowouts, cratering, explosives and other environmental damage that may result in personal injuries, property damage, damage to productive formations or equipment and environmental damages. Any uninsured costs would be deducted as a production cost in calculating net proceeds payable to the Trust.

Most of the gas produced in the San Juan Basin is transported on one of only two major pipelines in the area, and transportation of this gas is generally controlled by a small number of distribution companies. Accordingly, any disruptions to transportation lines or increases in transportation costs for production from these properties could also affect the Trust.

The operators of the working interest owner are subject to extensive governmental regulation.

Oil and gas operations have been, and in the future will be, affected by federal, state and local laws and regulations and other political developments, such as price or gathering rate controls and environmental protection regulations.

None of the Trustee, the Trust nor its unitholders control the operation or development of the Royalty Properties and have little influence over operation or development.

Neither the Trustee nor the unitholders can influence or control the operation or future development of the underlying properties. The Royalty Properties are owned by independent working interest owners. The working interest owners manage the underlying properties and handle receipt and payment of funds relating to the Royalty Properties and payments to the Trust for the Royalty.

The current working interest owners are under no obligation to continue operating the properties. Neither the Trustee nor the unitholders have the right to replace an operator.

The owner of any Royalty Property may abandon any property, terminating the related Royalty.

The working interest owners may at any time transfer all or part of the Royalty Property to another unrelated third party. Unitholders are not entitled to vote on any transfer, and the Trust will not receive any proceeds of any such transfer. Following any transfer, the Royalty Properties will continue to be subject to the Royalty, but the net proceeds from the transferred property would be calculated separately and paid by the transferee. The transferee would be responsible for all of the obligations relating to calculating, reporting and paying to the Trust the Royalty on the transferred portion of the Royalty Properties, and the current owner of the Royalty Properties would have no continuing obligation to the Trust for those properties.

The current working interest owners or any transferee may abandon any well or property if it reasonably believes that the well or property can no longer produce in commercially economic quantities. This could result in termination of the Royalty relating to the abandoned well.

The Royalty can be sold and the Trust can be terminated.

The Trust will be terminated and the Trustee must sell the Royalty if holders of a majority of the units of beneficial interest of the Trust approve the sale or vote to terminate the Trust, or if the Trust's royalty income for each of two successive years is less than $250,000 per year. Following any such termination and liquidation, the net proceeds of any sale will be distributed to the unitholders and unitholders will receive no further distributions from the Trust. We cannot assure you that any such sale will be on terms acceptable to all unitholders.

Trust assets are depleting assets and, if the working interest owners or other operators of the Royalty Properties do not perform additional development projects, the assets may deplete faster than expected.

The net proceeds payable to the Trust are derived from the sale of depleting assets. Accordingly, the portion of the distributions to unitholders attributable to depletion may be considered a return of capital. The reduction in proved reserve quantities is a common measure of depletion. Future maintenance and development projects on the Royalty Properties will affect the quantity of proved reserves. The timing and size of these projects will depend on the market prices of natural gas. If operators of the Royalty Properties do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust. For federal income tax purposes, depletion is reflected as a deduction, which is dependent upon the purchase price of a unit. Please see the section entitled "—Description of the Units—Federal Income Tax Matters" under Item 1 of this Form 10-K.

Unitholders have limited voting rights.

Voting rights as a unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of unitholders or for an annual or other periodic re-election of the Trustee. Unlike corporations which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a corporate Trustee in accordance with the Trust Indenture and other organizational documents. The Trustee has extremely limited discretion in its administration of the Trust.

Unitholders have limited ability to enforce the Trust's rights against the current or future owners of the Royalty Properties.

The Trust Agreement and related trust law permit the Trustees and the Trust to sue the working interest owners to compel them to fulfill the terms of the Conveyance of the Royalty. If the Trustee does not take appropriate action to enforce provisions of the Conveyance, the recourse of a unitholder would likely be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. Unitholders probably would not be able to sue the working interest owners directly.

Item 2. Properties.

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

Item 3. Legal Proceedings.

There are no pending legal proceedings to which the Trust is a named party. However, PNR has informed the Trust that PNR is party to a 1993 class action lawsuit filed in the 26th Judicial District Court of Stevens County, Kansas by two classes of royalty owners, one for each of PNR's gathering systems connected to PNR's Satanta gas plant. The case was relatively inactive for several years. In early 2000, the plaintiffs amended their pleadings and it now contains two material claims. First, the plaintiffs assert that they were improperly charged expenses (primarily field compression), which are a "cost of production", and for which the plaintiffs, as royalty owners, are not responsible. Second, the plaintiffs claim they are entitled to 100 percent of the value of the helium extracted at the PNR's Satanta gas plant. If the plaintiffs were to prevail on the above two claims in their entirety, it is possible that the PNR's liability (both for periods covered by the lawsuit and from the last date covered by the lawsuit to the present—because the deductions continue to be taken and the plaintiffs continue to be paid for a royalty share of the helium) could reach $65.0 million, plus prejudgment interest. PNR has advised that the Trust's share of this amount could exceed $3.0 million. However, PNR believes it has valid defenses to the plaintiffs' claims, has paid the plaintiffs properly under their respective oil and gas leases and other agreements, and intends to vigorously defend itself.

PNR does not believe the costs it has deducted are a "cost of production". The costs being deducted are post-production costs incurred to transport the gas to PNR's Satanta gas plant for processing, where the valuable hydrocarbon liquids and helium are extracted from the gas. The plaintiffs benefit from these extractions, and PNR believes that charging the plaintiffs with their proportionate share of these transportation and processing expenses is consistent with Kansas law and with the parties' agreements.

PNR has also vigorously defended against plaintiffs' claims to 100 percent of the value of the helium extracted, and believes that in accordance with applicable law, it has properly accounted to the plaintiffs for their fractional royalty share of the helium under the specified royalty clauses of the respective oil and gas leases.

The factual evidence in the case was presented to the 26th Judicial District Court without a jury in December 2001. Oral arguments were heard by the court in April 2002, and although the court has not yet entered a judgment or findings, it could do so at any time. PNR strongly denies the existence of any material underpayment to the plaintiffs and believes it presented strong evidence at trial to support its positions.

Entry of a final judgment adverse to PNR would reduce any amount available for distribution to the Trust for the period in which liability is recorded and during periods required for PNR to recoup any additional amounts.

Item 4. Submission of Matters to a Vote of Security Holders.

There were no matters submitted to a vote of security holders during the fourth quarter of 2003.

PART II

Item 5. Market for the Registrant's Common Equity and Related Unitholder Matters.

The units of beneficial interest of the Trust are traded on the New York Stock Exchange—ticker symbol "MTR". The high and low sales prices and distributions per unit for each quarter in the two years ended December 31, 2003, were as follows:

	2003			2002		
Quarter	**High**	**Low**	**Distribution**	**High**	**Low**	**Distribution**
First	$49.50	$41.10	$1.1091	$39.13	$36.01	$0.4791
Second	$54.70	$43.85	$1.4726	$39.93	$37.26	$0.5801
Third	$53.00	$49.75	$1.2291	$39.98	$32.74	$0.7974
Fourth	$57.25	$50.80	$1.1612	$42.41	$39.26	$0.7267

At March 8, 2004, the 1,863,590 units outstanding were held by 1,169 unitholders of record.

Item 6. Selected Financial Data.

	2003	2002	2001	2000	1999
Royalty income	$ 9,299,034	$ 4,841,115	$10,490,988	$ 7,960,109	$ 5,475,497
Distributable income	$ 9,265,740	$ 4,814,201	$10,566,751	$ 8,030,448	$ 5,504,362
Distributable income per unit	$ 4.9720	$ 2.5833	$ 5.6701	$ 4.3091	$ 2.9536
Total assets at year end	$11,711,640	$11,431,621	$12,037,014	$14,545,212	$14,358,414

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

The following review of the Trust's financial condition and results of operations should be read in conjunction with the financial statements and notes thereto. The discussion of net production attributable to the Hugoton and San Juan properties represents production volumes that are to a large extent hypothetical as the Trust does not own and is not entitled to any specific production volumes. See Note 7 to the financial statements. Any discussion of "actual" production volumes represents the hydrocarbons that were produced from the properties in which the Trust has a net profits overriding royalty interest.

Critical Accounting Policies

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income recorded for a month is the amount computed and paid by the working interest owners to the Trustee for such month rather than either the value of a portion of the oil and gas produced by the working interest owners for such month or the amount subsequently determined to be the Trust's proportionate share of the net proceeds for such month;

(b) Interest income, interest receivable and distributions payable to unitholders include interest to be earned on short-term investments from the financial statement date through the next date of distribution; and

(c) Trust general and administrative expenses, net of reimbursements, are recorded in the month they accrue.

This basis for reporting distributable income is considered to be the most meaningful because distributions to the unitholders for a month are based on net cash receipts for such month. However, these statements differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America because, under such principles, royalty income for a month would be based on net proceeds from production for such month without regard to when calculated or received and interest income for a month would be calculated only through the end of such month.

Liquidity and Capital Resources

As discussed under "Description of the Trust" in Item 1 of this Form 10-K, the Trust's source of cash is the Royalty income received from its share of the net proceeds from the Royalty Properties. Reference is made to Note 7 in the Notes to Financial Statements under Item 8 of this Form 10-K for estimates of future Royalty income attributable to the Royalty.

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

Financial Review

Years 2003 and 2002

	Years Ended December 31,	
	2003	2002
Royalty income	$9,299,034	$4,841,115
Interest income	13,831	10,737
General and administrative expenses	(47,125)	(37,651)
Distributable income	$9,265,740	$4,814,201
Distributable income per unit	$ 4.9720	$ 2.5833

The Trust's Royalty income was $9,299,034 in 2003, an increase of approximately 92% as compared to $4,841,115 in 2002, primarily as a result of higher natural gas and natural gas liquid prices in 2003.

Royalty income from the Hugoton Royalty Properties was $5,277,509 in 2003, an increase of approximately 75%, as compared to $3,014,133 in 2002, primarily as a result of higher natural gas and natural gas liquid prices in 2003.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $5.04 per Mcf and $21.73 per barrel, respectively, in 2003 as compared to $2.68 per Mcf and $14.25 per barrel, respectively, in 2002. Net production attributable to the Hugoton Royalty was 815,517 Mcf of natural gas and 53,718 barrels of natural gas liquids in 2003 as compared with 797,160 Mcf of natural gas and 61,596 barrels of natural gas liquids in 2002. Actual production volumes attributable to the Hugoton properties was 1,046,651 Mcf of natural gas and 53,721 barrels of natural gas liquids in 2003 as compared with 1,196,484 Mcf of natural gas and 61,593 barrels of natural gas liquids in 2002.

Royalty income from the San Juan Basin Royalty properties is calculated and paid to the Trust on a state-by-state basis. Royalty income from the San Juan Basin Royalty Properties located in the state of New Mexico was $4,021,525 in 2003 as compared to $1,826,982 in 2002, an increase of 120%. The increase in Royalty income was due to increased natural gas and natural gas liquids prices in 2003 and lower capital expenditures in 2003 when compared to 2002. No Royalty income was received from the San Juan Basin Royalty Properties located in the state of Colorado in 2003 or 2002, as costs associated with the Fruitland Coal drilling program on Royalty Properties in that state have not been fully recovered. The San Juan Basin development drilling program has no effect on Royalty income or distributions relating to the Hugoton Royalty.

The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty properties was $4.34 per Mcf and $22.07 per barrel, respectively, in 2003 compared with $2.54 per Mcf and $16.26 per barrel, respectively, in 2002. Net production attributable to the San Juan Basin Royalty was 705,765 Mcf of natural gas and 43,430 barrels of natural gas liquids, oil and condensate in 2003 as compared to 423,304 Mcf of natural gas and 46,235 barrels of natural gas liquids, oil and condensate in 2002. Actual production volumes attributable to the San Juan Basin properties was 1,142,236 Mcf of natural gas and 57,522 barrels of natural gas liquids, oil and condensate in 2003 as compared with 1,326,650 Mcf of natural gas and 64,615 barrels of natural gas liquids, oil and condensate in 2002.

Years 2002 and 2001

	Years Ended December 31,	
	2002	**2001**
Royalty income	$4,841,115	$10,490,988
Interest income	10,737	103,129
General and administrative expenses	(37,651)	(27,366)
Distributable income	$4,814,201	$10,566,751
Distributable income per unit	$ 2.5833	$ 5.6701

The Trust's Royalty income was $4,841,115 in 2002, a decrease of approximately 54% as compared to $10,490,988 in 2001, primarily as a result of lower natural gas, natural gas liquid prices and lower gas production from the Hugoton Royalty Properties in 2002.

Royalty income from the Hugoton Royalty Properties was $3,014,133 in 2002, a decrease of approximately 57%, as compared to $7,034,366 in 2001, primarily as a result of lower natural gas, natural gas liquid prices and lower gas production from the Hugoton Royalty Properties in 2002.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $2.68 per Mcf and $14.25 per barrel, respectively, in 2002 as compared to $4.82 per Mcf and $21.91 per barrel, respectively in 2001. Net production attributable to the Hugoton Royalty was 797,160 Mcf of natural gas and 61,596 barrels of natural gas liquids in 2002 as compared with 1,151,003 Mcf of natural gas and 67,847 barrels of natural gas liquids in 2001. Actual production volumes attributable to the Hugoton properties was 1,196,484 Mcf of natural gas and 61,593 barrels of natural gas liquids in 2002 as compared with 1,379,514 Mcf of natural gas and 67,932 barrels of natural gas liquids in 2001.

Royalty income from the San Juan Basin Royalty properties is calculated and paid to the Trust on a state-by-state basis. Royalty income from the San Juan Basin Royalty Properties located in the state of New Mexico was $1,826,982 in 2002 as compared to $3,456,622 in 2001. The decrease in Royalty income was due primarily to decreased natural gas and natural gas liquids prices in 2002. No Royalty income was received from the San Juan Basin Royalty Properties located in the state of Colorado in 2002 or 2001, as costs associated with the Fruitland Coal drilling program on Royalty Properties in that state have not been fully recovered. The San Juan Basin development drilling program has no effect on Royalty income or distributions relating to the Hugoton Royalty.

The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty properties was $2.54 per Mcf and $16.26 per barrel, respectively, in 2002 compared with $4.21 per Mcf and $22.15 per barrel, respectively in 2001. Net production attributable to the San Juan Basin Royalty was 423,304 Mcf of natural gas and 46,235 barrels of natural gas liquids, oil and condensate in 2002 as compared to 592,443 Mcf of natural gas and 43,451 barrels of natural gas liquids, oil and condensate in 2001. Actual production volumes attributable to the San Juan Basin properties was 1,326,650 Mcf of natural gas and 64,615 barrels of natural gas liquids, oil and condensate in 2002 as compared with 1,311,686 Mcf of natural gas and 56,870 barrels of natural gas liquids in 2001.

SUMMARY OF ROYALTY INCOME, PRODUCTION AND AVERAGE PRICES (Unaudited)

	Hugoton		San Juan Basin		Total	
	Natural Gas	Natural Gas Liquids(2)	Natural Gas	Oil, Condensate and Natural Gas Liquids(2)	Natural Gas	Oil, Condensate and Natural Gas Liquids(2)
Year ended December 31, 2003:						
The Trust's proportionate share of—						
Gross proceeds	$ 5,347,000	$1,167,303	$ 5,270,667	$ 1,269,454	$10,617,667	$ 2,436,757
Less the Trust's proportionate share of—						
Capital costs recovered(1)	(156,881)	—	(255,722)	—	(412,603)	—
Operating costs	(1,079,913)	—	(1,929,233)	(310,950)	(3,009,146)	(310,950)
Interest on cost carryforward	—	—	(22,691)	—	(22,691)	—
Royalty income	$ 4,110,206	$1,167,303	$ 3,063,021	$ 958,504	$ 7,173,227	$ 2,125,807
Average sales price	$ 5.04	$ 21.73	$ 4.34	$ 22.07	$ 4.72	$ 21.88
	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Net production volumes attributable to the Royalty paid	815,517	53,718	705,765	43,430	1,521,282	97,149
Year ended December 31, 2002:						
The Trust's proportionate share of—						
Gross proceeds	$ 3,202,189	$ 877,745	$ 3,510,634	$ 1,050,782	$ 6,712,823	$ 1,928,527
Less the Trust's proportionate share of—						
Capital costs recovered(1)	(14,661)	—	(683,455)	—	(698,116)	—
Operating costs	(1,051,140)	—	(1,730,011)	(298,993)	(2,781,151)	(298,993)
Interest on cost carryforward	—	—	(21,975)	—	(21,975)	—
Royalty income	$ 2,136,388	$ 877,745	$ 1,075,193	$ 751,789	$ 3,211,581	$ 1,629,534
Average sales price	$ 2.68	$ 14.25	$ 2.54	$ 16.26	$ 2.63	$ 15.11
Net production volumes attributable to the Royalty paid	**(Mcf)** 797,160	**(Bbls)** 61,596	**(Mcf)** 423,304	**(Bbls)** 46,235	**(Mcf)** 1,220,464	**(Bbls)** 107,831
Year ended December 31, 2001:						
The Trust's proportionate share of—						
Gross proceeds	$ 6,644,453	$1,488,517	$ 5,804,245	$ 1,259,488	$12,448,698	$ 2,748,005
Less the Trust's proportionate share of—						
Capital costs recovered(1)	(68,052)	—	(1,305,601)	—	(1,373,653)	—
Operating costs	(1,028,567)	(1,985)	(1,982,194)	(297,053)	(3,010,761)	(299,038)
Interest on cost carryforward	—	—	(22,263)	—	(22,263)	—
Royalty income	$ 5,547,834	$1,486,532	$ 2,494,187	$ 962,435	$ 8,042,021	$ 2,448,967
Average sales price	$ 4.82	$ 21.91	$ 4.21	$ 22.15	$ 4.59	$ 22.00
Net production volumes attributable to the Royalty paid	**(Mcf)** 1,151,003	**(Bbls)** 67,847	**(Mcf)** 592,443	**(Bbls)** 43,451	**(Mcf)** 1,743,446	**(Bbls)** 111,298

For a discussion of the method used to compute the net production volumes in the table above, see Note 3 in the Notes to Financial Statements.

(1) Capital costs recovered represents capital costs incurred during the current or prior periods to the extent that such costs have been recovered by the applicable working interest owners from current period gross proceeds. Cost carryforward represents capital costs incurred during the current or prior periods which will be recovered from future period gross proceeds. The cost carryforward resulting from the Fruitland Coal drilling program was $256,361, $303,581, and $255,551 at December 31, 2003, 2002 and 2001, respectively, and relates solely to the San Juan Basin Colorado properties. See "Description of Royalty Properties—San Juan Basin Fruitland Coal Drilling" for additional information regarding the Fruitland Coal drilling program.

(2) Gross proceeds attributable to natural gas liquids for the Hugoton and San Juan Basin properties are net of a volumetric in-kind processing fee retained by PNR and ConocoPhillips, respectively.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Not applicable.

Item 8. Financial Statements and Supplementary Data.

MESA ROYALTY TRUST
STATEMENTS OF DISTRIBUTABLE INCOME

	Years Ended December 31,		
	2003	**2002**	**2001**
Royalty income	$9,299,034	$4,841,115	$10,490,988
Interest income	13,831	10,737	103,129
General and administrative expenses	(47,125)	(37,651)	(27,366)
Distributable income	$9,265,740	$4,814,201	$10,566,751
Distributable income per unit	$ 4.9720	$ 2.5833	$ 5.6701

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31,	
	2003	**2002**
ASSETS		
Cash and short-term investments	$ 2,161,640	$ 1,351,189
Interest receivable	2,308	3,000
Net overriding royalty interests in oil and gas properties	42,498,034	42,498,034
Less: accumulated amortization	(32,950,342)	(32,420,602)
Total assets	$ 11,711,640	$ 11,431,621
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 2,163,948	$ 1,354,189
Trust corpus (1,863,590 units of beneficial interest authorized and outstanding)	9,547,692	10,077,432
Total liabilities and trust corpus	$ 11,711,640	$ 11,431,621

STATEMENTS OF CHANGES IN TRUST CORPUS

	Years Ended December 31,		
	2003	**2002**	**2001**
Trust corpus, beginning of year	$10,077,432	$10,865,266	$ 11,861,903
Distributable income	9,265,740	4,814,201	10,566,751
Distributions to unitholders	(9,265,740)	(4,814,201)	(10,566,751)
Amortization of net overriding royalty interests	(529,740)	(787,834)	(996,637)
Trust corpus, end of year	$ 9,547,692	$10,077,432	$ 10,865,266

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

MESA ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS

(1) Trust Organization and Provisions

The Mesa Royalty Trust (the "Trust") was created on November 1, 1979. On that date, Mesa Petroleum Co., predecessor to Mesa Limited Partnership ("MLP") which was the predecessor to MESA Inc., conveyed to the Trust a 90% net overriding royalty interest (the "Royalty") in certain producing oil and gas properties located in the Hugoton field of Kansas, the San Juan Basin field of New Mexico and Colorado and the Yellow Creek field of Wyoming (the "Royalty Properties"). On April 30, 1991, MLP sold its interests in the Royalty Properties located in San Juan Basin field to ConocoPhillips. ConocoPhillips sold the portion of its interests in the San Juan Basin Royalty Properties located in Colorado to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the Colorado San Juan Basin Royalty Properties to BP Amoco Production Company ("BP Amoco"), a subsidiary of BP Amoco. Until August 7, 1997, MESA Inc. operated the Hugoton Royalty Properties through Mesa Operating Co., a wholly owned subsidiary of MESA Inc. On August 7, 1997, MESA Inc. merged with and into Pioneer Natural Resources Company ("Pioneer"), formerly a wholly owned subsidiary of MESA Inc., and Parker & Parsley Petroleum Company merged with and into Pioneer Natural Resources USA, Inc. (successor to Mesa Operating Co.), a wholly owned subsidiary of Pioneer ("PNR") (collectively, the mergers are referred to herein as the "Merger"). Subsequent to the Merger, the Hugoton Royalty Properties have been operated by PNR. The San Juan Basin Royalty Properties located in New Mexico are operated by ConocoPhillips. The San Juan Basin Royalty Properties located in Colorado are operated by BP Amoco. As used in this report, PNR refers to the operator of the Hugoton Royalty Properties, ConocoPhillips refers to the operator of the San Juan Basin Royalty Properties, other than the portion of such properties located in Colorado, and BP Amoco refers to the operator of the Colorado San Juan Basin Royalty Properties unless otherwise indicated.

JPMorgan Chase Bank is trustee for the Trust (the "Trustee"). JPMorgan Chase Bank was formerly known as The Chase Manhattan Bank, and is the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association. The terms of the Mesa Royalty Trust Indenture (the "Trust Indenture") provide, among other things, that:

(a) the Trust cannot engage in any business or investment activity or purchase any assets;

(b) the Royalty can be sold in part or in total for cash upon approval of the unitholders;

(c) the Trustee can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payment of the borrowings;

(d) the Trustee will make cash distributions to the unitholders in January, April, July and October each year as discussed more fully in Note 4;

(e) the Trust will terminate upon the first to occur of the following events: (i) at such time as the Trust's royalty income for each of two successive years is less than $250,000 per year or (ii) a vote by the unitholders in favor of termination. Upon termination of the Trust, the Trustee will sell for cash all the assets held in the Trust estate and make a final distribution to unitholders of any funds remaining after all Trust liabilities have been satisfied; and

(f) PNR, ConocoPhillips, and BP Amoco (collectively the "Working Interest Owners") will reimburse the Trust for 59.34%, 27.45% and 1.77%, respectively, for general and administrative expenses of the Trust.

(2) Net Overriding Royalty Interest

In accordance with the instruments conveying the Royalty, the Working Interest Owners will calculate and pay the Trust each month an amount equal to 90% of the net proceeds for the preceding month. The Trust Indenture was amended in 1985, the effect of which was an overall reduction of approximately 88.56% in the size of the Trust; therefore, the Trust is now entitled to receive 90% of 11.44% of the net proceeds for the preceding month. Generally, net proceeds means the excess of the amounts received by the Working Interest Owners from sales of oil and gas from the Royalty Properties over the operating and capital costs incurred.

Amortization of the Royalty is computed on a unit-of-production basis and is charged directly to trust corpus since such amount does not affect distributable income.

(3) Basis of Accounting

The financial statements of the Trust are prepared on the following basis:

(a) Royalty income recorded for a month is the amount computed and paid by the working interest owners to the Trustee for such month rather than either the value of a portion of the oil and gas produced by the working interest owners for such month or the amount subsequently determined to be the Trust's proportionate share of the net proceeds for such month;

(b) Interest income, interest receivable and distributions payable to unitholders include interest to be earned on short-term investments from the financial statement date through the next date of distribution; and

(c) Trust general and administrative expenses, net of reimbursements, are recorded in the month they accrue.

This basis for reporting distributable income is considered to be the most meaningful because distributions to the unitholders for a month are based on net cash receipts for such month. However, these statements differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America because, under such principles, royalty income for a month would be based on net proceeds from production for such month without regard to when calculated or received and interest income for a month would be calculated only through the end of such month.

(4) Distributions to Unitholders

Under the terms of the Trust Indenture, the Trustee must distribute to the unitholders all cash receipts, after paying liabilities and providing for cash reserves as determined necessary by the Trustee. The amounts distributed are determined on a monthly basis and are payable to unitholders of record as of the last business day of each month. However, cash distributions are made quarterly in January, April, July and October, and include interest earned from the monthly record dates to the date of the distribution.

(5) Federal Income Taxes

In a technical advice memorandum dated February 26, 1982, the IRS advised the Dallas District Director that the Trust is classifiable as a grantor trust and not as an association taxable as a corporation.

(5) Federal Income Taxes (Continued)

As a grantor trust, the Trust will incur no federal income tax liability.

(6) PNR Legal Proceedings

PNR has informed the Trust that PNR is party to a 1993 class action lawsuit filed in the 26th Judicial District Court of Stevens County, Kansas by two classes of royalty owners, one for each of PNR's gathering systems connected to PNR's Satanta gas plant. The case was relatively inactive for several years. In early 2000, the plaintiffs amended their pleadings and it now contains two material claims. First, the plaintiffs assert that they were improperly charged expenses (primarily field compression), which are a "cost of production", and for which the plaintiffs, as royalty owners, are not responsible. Second, the plaintiffs claim they are entitled to 100 percent of the value of the helium extracted at the PNR's Satanta gas plant. If the plaintiffs were to prevail on the above two claims in their entirety, it is possible that the PNR's liability (both for periods covered by the lawsuit and from the last date covered by the lawsuit to the present—because the deductions continue to be taken and the plaintiffs continue to be paid for a royalty share of the helium) could reach $65.0 million, plus prejudgment interest. PNR has advised that the Trust's share of this amount could exceed $3.0 million. However, PNR believes it has valid defenses to the plaintiffs' claims, has paid the plaintiffs properly under their respective oil and gas leases and other agreements, and intends to vigorously defend itself.

PNR does not believe the costs it has deducted are a "cost of production". The costs being deducted are post-production costs incurred to transport the gas to PNR's Satanta gas plant for processing, where the valuable hydrocarbon liquids and helium are extracted from the gas. The plaintiffs benefit from these extractions, and PNR believes that charging the plaintiffs with their proportionate share of these transportation and processing expenses is consistent with Kansas law and with the parties' agreements.

PNR has also vigorously defended against plaintiffs' claims to 100 percent of the value of the helium extracted, and believes that in accordance with applicable law, it has properly accounted to the plaintiffs for their fractional royalty share of the helium under the specified royalty clauses of the respective oil and gas leases.

The factual evidence in the case was presented to the 26th Judicial District Court without a jury in December 2001. Oral arguments were heard by the court in April 2002, and although the court has not yet entered a judgment or findings, it could do so at any time. PNR strongly denies the existence of any material underpayment to the plaintiffs and believes it presented strong evidence at trial to support its positions.

Entry of a final judgment adverse to PNR would reduce any amount available for distribution to the Trust for the period in which liability is recorded and during periods required for PNR to recoup any additional amounts.

(7) Supplemental Reserve Information (Unaudited)

Estimates of the proved oil and gas reserves attributable to the Hugoton Royalty Properties as of December 31, 2003, 2002 and 2001 are based on reports prepared by PNR. The estimates were prepared in accordance with guidelines established by the Securities and Exchange Commission (the "SEC"). Accordingly, the estimates were based on existing economic and operating conditions. The reserve volumes and revenue values for the Trust net profits interest were estimated by allocating to the

(7) Supplemental Reserve Information (Unaudited) (Continued)

Trust a portion of the estimated combined net reserve volumes of the Hugoton Royalty Properties based on future net revenue. Production volumes are allocated based on royalty income. Because the net reserve volumes attributable to the Trust net profits interest are estimated using an allocation of reserve volumes based on estimates of future net revenue, a change in prices or costs will result in changes in the estimated net reserve volumes. Therefore, the estimated net reserve volumes attributable to the Trust net profits interest will vary if different future price and cost assumptions are used. Only costs necessary to develop and produce existing proved reserve volumes were assumed in the allocation of reserve volumes to the Royalty.

Estimates of proved oil and gas reserves attributable to the New Mexico portion of the San Juan Basin Royalty Properties are based on a reserve report prepared by ConocoPhillips. These estimates were prepared in accordance with SEC regulations and on a basis generally consistent with those used to derive the oil and gas reserves attributable to the Hugoton Royalty Properties.

Estimates of proved oil and gas reserves attributable to the Colorado portion of the San Juan Basin Royalty Properties have been omitted from the Trust's reserve disclosures, as they represent less than 5% of the Trust's total reserves and future net revenues.

Future prices for natural gas and oil, condensate and natural gas liquids were based on prices at each year end. Operating costs, production and ad valorem taxes and future development and abandonment costs were based on current costs as of each year end, with no escalation.

There are numerous uncertainties inherent in estimating the quantities and value of proved reserves and in projecting the future rates of production and timing of expenditures. The reserve data below represent estimates only and should not be construed as being exact. Moreover, the discounted values should not be construed as representative of the current market value of the Royalty. A market value determination would include many additional factors including: (i) anticipated future oil and gas prices; (ii) the effect of federal income taxes, if any, on the future royalties; (iii) an allowance for return on investment; (iv) the effect of governmental legislation; (v) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities; and (vi) other business risks.

Estimates of reserve volumes attributable to the Royalty are shown in order to comply with requirements of the SEC. There is no precise method of allocating estimates of physical quantities of reserve volumes between the Working Interest Owners and the Trust, since the Royalty is not a working interest and the Trust does not own and is not entitled to receive any specific volume of reserves from the Royalty. The quantities of reserves attributable to the Trust have been and will be affected by changes in various economic factors utilized in estimating net revenues from the Royalty Properties. Therefore, the estimates of reserve volumes set forth below are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest.

The following schedules set forth (i) the estimated net quantities of proved and proved developed oil, condensate and natural gas liquids and natural gas reserves attributable to the Royalty, and (ii) the standardized measure of the discounted future royalty income attributable to the Royalty and the nature of changes in such standardized measure between years. These schedules are prepared on the accrual basis, which is the basis on which the Working Interest Owners maintain their production records and is different from the basis on which the Royalty is computed.

(7) Supplemental Reserve Information (Unaudited) (Continued)

ESTIMATED QUANTITIES OF PROVED AND PROVED DEVELOPED RESERVES

(Unaudited)

	Oil, Condensate and Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Reserves:		
December 31, 2000	2,355,910	40,858,631
Revisions to previous estimates	(597,032)	(11,269,142)
Production	(111,298)	(1,752,012)
December 31, 2001	1,647,580	27,837,477
Revisions to previous estimates	299,279	4,306,509
Production	(107,382)	(1,220,464)
December 31, 2002	1,839,477	30,923,522
Revisions to previous estimates	798,050	2,038,687
Production	(97,149)	(1,521,282)
December 31, 2003	2,540,378	31,440,927
Proved Developed Reserves:		
December 31, 2000	2,285,910	39,850,631
December 31, 2001	1,609,580	13,703,038
December 31, 2002	1,789,477	30,164,322
December 31, 2003	2,487,378	30,953,927

- The estimated quantities of proved reserves for oil, condensate and natural gas liquids include oil and condensate reserves at December 31 of the respective years as follows: 2003, 80,000 Bbls; 2002, 79,000 Bbls; and 2001, 56,000 Bbls.

- The Hugoton Royalty represents 23%, 38%, and 43% of the estimated proved oil, condensate and natural gas liquids reserves and 42%, 44%, and 49% of the estimated proved natural gas reserves as of December 31 of 2003, 2002 and 2001, respectively.

(7) Supplemental Reserve Information (Unaudited) (Continued)

STANDARDIZED MEASURE OF FUTURE ROYALTY INCOME FROM PROVED OIL AND GAS RESERVES, DISCOUNTED AT 10% PER ANNUM (Unaudited)

	December 31,		
	2003	2002	2001
	(In thousands)		
The Trust's proportionate share of future gross proceeds	$ 310,365	$249,610	$141,424
Less the Trust's proportionate share of—			
Future operating costs	(89,163)	(76,163)	(56,372)
Future capital costs	(3,295)	(2,389)	(2,561)
Future royalty income	217,907	171,058	82,491
Discount at 10% per annum	(126,145)	(97,273)	(47,116)
Standardized measure of future royalty income from proved oil and gas reserves	$ 91,762	$ 73,785	$ 35,375

CHANGES IN THE STANDARDIZED MEASURE OF FUTURE ROYALTY INCOME FROM PROVED OIL AND GAS RESERVES, DISCOUNTED AT 10% PER ANNUM (Unaudited)

	December 31,		
	2003	2002	2001
	(In thousands)		
Standardized measure at beginning of year	$ 73,785	$ 35,375	$ 176,751
Revisions of previous estimates	8,871	9,320	(21,569)
Net changes in price and production costs	11,026	30,394	(126,991)
Royalty income	(9,299)	(4,841)	(10,491)
Accretion of discount	7,379	3,537	17,675
Net changes in standardized measure	17,977	38,410	(141,376)
Standardized measure at end of year	$ 91,762	$ 73,785	$ 35,375

- The Hugoton Royalty represents approximately 42% and 47% of the standardized measure of future royalty income for 2003 and 2002, respectively.
- Standardized measure at December 31, 2003 was calculated using natural gas prices of $5.69 per Mcf for Hugoton properties and $4.69 per Mcf for San Juan properties.

(8) Selected Quarterly Financial Data (Unaudited)

	Summarized Quarterly Results Three Months Ended			
	March 31	June 30	September 30	December 31
2003:				
Royalty income	$2,074,269	$2,751,725	$2,300,957	$2,172,083
Distributable income	$2,066,928	$2,744,271	$2,290,593	$2,163,948
Distributable income per unit	$ 1.1091	$ 1.4726	$ 1.2291	$ 1.1612
2002:				
Royalty income	$ 903,004	$1,091,185	$1,488,156	$1,358,770
Distributable income	$ 892,930	$1,081,100	$1,485,982	$1,354,189
Distributable income per unit	$ 0.4791	$ 0.5801	$ 0.7974	$ 0.7267

INDEPENDENT AUDITORS' REPORT

JPMorgan Chase Bank (Trustee)
and the Unitholders of the Mesa Royalty Trust:

We have audited the accompanying statements of assets, liabilities and trust corpus of the Mesa Royalty Trust as of December 31, 2003 and 2002, and the related statements of distributable income and changes in trust corpus for the years then ended. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits. The 2001 financial statements of the Mesa Royalty Trust were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated March 25, 2002.

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.

These financial statements were prepared on the basis of accounting described in Note 3, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the Mesa Royalty Trust as of December 31, 2003 and 2002 and its distributable income and changes in trust corpus for the years then ended on the basis of accounting described in Note 3.

KPMG LLP

Houston, Texas
March 12, 2004

1. This report is a copy of a previously issued report (See page 34 of the Trust's Annual Report for December 31, 2001 on Form 10-K)
2. The predecessor auditor has not reissued this report.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To JPMorgan Chase Bank (Trustee)
and the Unitholders of the Mesa Royalty Trust:

We have audited the accompanying statements of assets, liabilities and trust corpus of the Mesa Royalty Trust as of December 31, 2001 and 2000, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2001. 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. 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 management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

These financial statements were prepared on the basis of accounting described in Note 3, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the Mesa Royalty Trust as of December 31, 2001 and 2000, and its distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2001, on the basis of accounting described in Note 3.

ARTHUR ANDERSEN LLP

Houston, Texas
March 25, 2002

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 ensure that information required to be disclosed by the Trust is accumulated and communicated by the working interest owners to JPMorgan Chase Bank, as Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the Trustee carried out an evaluation of the Trustee's disclosure controls and procedures. Mike Ulrich, as Trust Officer of the Trustee, has concluded that the controls and procedures are effective, while noting certain limitations on disclosure controls and procedures as set forth below.

Due to the contractual arrangements of (i) the Trust Indenture, and (ii) the rights of the Trust under the Conveyance regarding information furnished by the working interest owners, there are certain potential weaknesses that are not subject to change or modification by the Trustee or its employees. The contractual limitations creating potential weaknesses in disclosure controls and procedures may be deemed to include:

- The working interest owners alone control (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, (iii) geological data relating to reserves, as well as the reserve report that contains projected production, operating expenses and capital expenses, and (iv) information relating to projected production. While the Trustee requests material information for use in periodic reports as part of its disclosure controls and procedures, the Trustee does not control this information and relies entirely on the working interest owners to provide accurate and timely information when requested for use in the Trust's periodic reports.
- Under the terms of the Trust Agreement, the Trustee is entitled to rely, and in fact relies, on certain experts in good faith, including the independent auditors with respect to their audit of the Trust and review of financial data provided by the working interest owners. Other than contracting independent auditors and reviewing information supplied by the working interest owners, the Trustee makes no independent or direct verification of this financial information. While the Trustee has no reason to believe its reliance upon experts is unreasonable, this reliance on experts and limited 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 Indenture and those required under applicable law.

Changes in Internal Controls. To the knowledge of the Trustee, there have been no significant changes in the Trustee's internal controls or in other factors that could significantly affect the Trustee'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 the working interest owners.

PART III

Item 10. Directors and Executive Officers of the Registrant.

There are no directors or executive officers of the Registrant. The Trustee is a corporate trustee which may be removed by the affirmative vote of the majority at a meeting of the holders of units of beneficial interest of the Trust at which a quorum is present.

The Trust does not have a principal executive officer, principal financial officer, principal accounting officer or controller and, therefore, has not adopted a code of ethics applicable to such persons. The Trust does not have a board of directors or an audit committee, and therefore it does not have an audit committee financial expert.

Item 11. Executive Compensation.

Not applicable.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

(a) Security Ownership of Certain Beneficial Owners.

The following information has been taken from filings with the Securities and Exchange Commission on Schedules 13D and 13G and Form 4.

Title of Class of Voting Securities	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership(1)	Percent of Class
Units of Beneficial Interest	Alpine Capital, L.P. 201 Main Street, Suite 3100 Fort Worth, Texas 76102	637,116(2)	34.2%
Units of Beneficial Interest	Beck, Mack & Oliver LLC 330 Madison Avenue New York, NY 10017	329,457(3)	17.67%

(1) Under applicable regulations of the Securities and Exchange Commission, securities are deemed to be "beneficially" owned by a person who directly or indirectly holds or shares voting power or investment power with respect thereto.

(2) Information obtained from Schedule 13D Amendment No. 24 filed January 29, 2004 of Alpine Capital, L.P. ("Alpine"), Robert W. Bruce III, Algenpar, Inc. and J. Taylor Crandall and from the Form 4 filed by Alpine, Mr. Bruce, Algenpar, Inc. and Mr. Crandall on February 25, 2004. Alpine directly owns and has sole voting and dispositive power with respect to all of such units. Mr. Bruce, by virtue of his position as a general partner of Alpine may be deemed to be a beneficial owner of the 637,116 units owned by Alpine with shared voting and dispositive power with respect to all of such units. Mr. Crandall, by virtue of his position as President and sole stockholder of Algenpar, Inc., which is one of two general partners of Alpine, may also be deemed to be a beneficial owner of the 637,116 units owned by Alpine with shared voting and dispositive power with respect to all of such units.

(3) Information obtained from Schedule 13G filed January 27, 2004 of Beck, Mack & Oliver LLC ("BMO"). BMO has sole voting power over 312,673 of such units and shared dispositive power with respect to all of such units. All of such units are owned by the investment advisory clients of BMO.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control. Registrant knows of no arrangements, including the pledge of securities of the Registrant, the operation of which may at a subsequent date result in a change in control of the Registrant.

Item 13. Certain Relationships and Related Transactions.

Not applicable.

Item 14. Principal Accountant Fees and Services.

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional services firms and related fees are granted by the Trustee.

The following table presents fees for professional audit services rendered by KPMG LLP for the audit of the Mesa Royalty Trust financial statements for 2003 and 2002 and fees billed for other services rendered by KPMG LLP.

	2003	2002
Audit fees (1)	$145,200	$143,900
Audit related fees	—	—
Tax fees (2)	43,000	—
All other fees	—	—
Total fees	$188,200	$143,900

1) Audit fees consist of fees for the audit of the Mesa Royalty Trust financial statements and reimbursement for travel related expenses. The Mesa Royalty Trust is reimbursed by the working interest owners for 88.56% of general and administrative expenses incurred.

2) Tax fees consist of fees related to the Mesa Royalty Trust's tax information for its unitholders paid in 2003 related to 2002 tax work. The Mesa Royalty Trust is reimbursed by the working interest owners for 88.56% of general and administrative expenses incurred.

PART IV

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

(a)(1)Financial Statements

The following financial statements are set forth under Part II, Item 8 of this Annual Report on Form 10-K on the pages indicated.

(a)(2)Schedules

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

(a)(3)Exhibits

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference JPMorgan Chase Bank is successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association.)

Exhibit Number		SEC File or Registration Number	Exhibit Number
4(a)	*Mesa Royalty Trust Indenture between Mesa Petroleum Co. and Texas Commerce Bank National Association, as Trustee, dated November 1, 1979	2-65217	1(a)
4(b)	*Overriding Royalty Conveyance between Mesa Petroleum Co. and Texas Commerce Bank, as Trustee, dated November 1, 1979	2-65217	1(b)
4(c)	*First Amendment to the Mesa Royalty Trust Indenture dated as of March 14, 1985 (Exhibit 4(c) to Form 10-K for year ended December 31, 1984 of Mesa Royalty Trust)	1-7884	4(c)
4(d)	*Form of Assignment of Overriding Royalty Interest, effective April 1, 1985, from Texas Commerce Bank National Association, as Trustee, to MTR Holding Co. (Exhibit 4(d) to Form 10-K for year ended December 31, 1984 of Mesa Royalty Trust)	1-7884	4(d)
4(e)	*Purchase and Sale Agreement, dated March 25, 1991, by and among Mesa Limited Partnership, Mesa Operating Limited Partnership and ConocoPhillips, as amended on April 30, 1991 (Exhibit 4(e) to Form 10-K for year ended December 31, 1991 of Mesa Royalty Trust)	1-7884	4(e)
31	Certification furnished pursuant to Section 302 of the Sarbanes-Oxley Act of 2002		
32	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		

(b) Reports on Form 8-K.

Current Reports on Form 8-K were filed with the Securities and Exchange Commission on October 23, 2003, November 19, 2003, and December 19, 2003.

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.

MESA ROYALTY TRUST

By JPMORGAN CHASE BANK, TRUSTEE

By /s/ MIKE ULRICH

Mike Ulrich
Vice President & Trust Officer

March 12, 2004

The Registrant, Mesa Royalty Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided.

EXHIBIT INDEX

EXHIBIT NUMBER		SEC File or Registration Number	Exhibit Number
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31	Certification furnished pursuant to Section 302 of the Sarbanes-Oxley Act of 2002		
32	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		

* Previously filed with the Securities and Exchange Commission and incorporated herein by reference.

Auditors
KPMG LLP
Houston, Texas

Counsel
Andrews Kurth LLP
Houston, Texas

Mesa Royalty Trust
700 Lavaca
Austin, Texas 78701

Transfer Agent and Registrar
JPMorgan Chase Bank
Austin, Texas 78701

This Annual Report on Form 10-K was distributed to unitholders as an Annual Report. Additional copies of this Annual Report will be provided, without charge, and copies of exhibits hereto will be provided, upon payment of a reasonable fee, upon written request from any unitholder to:

Mesa Royalty Trust
JPMorgan Chase Bank, Trustee
Attention: Mike Ulrich, Institutional Trust Services
700 Lavaca
Austin, Texas 78701

This information may also be obtained from: www.businesswire.com/cnn/mtr.htm

Mesa Royalty Trust
700 LAVACA
AUSTIN, TEXAS 78701