MESA ROYALTY TRUST/TX
Form 10-K
April 02, 2007

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2006

Or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM TO

Commission file number: 1-7884

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.)
The Bank New York Trust Company, N.A., Trustee **919 Congress Avenue, 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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x

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

Indicate by check mark 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. x

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

Large accelerated filer o	Accelerated filer x	Non-accelerated filer o

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

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, 2006 of $63.15 was approximately $117,685,709.

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 14, 2007, 1,863,590 Units of Beneficial Interest were outstanding 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 Item 1A. 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, The Bank of New York Trust Company, N.A., (the Trustee), 919 Congress Avenue, Austin, Texas 78701. The telephone number of the Trust is 1-800-852-1422. The Bank of New York Trust Company, N.A., is the successor Trustee from JPMorgan Chase Bank, N.A., 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 most 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 Company (BP), a subsidiary of BP p.l.c. 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. All of the San Juan Basin Royalty Properties located in New Mexico and a few wells in Southwest Colorado, near the New Mexico border, are operated by ConocoPhillips. Substantially all of the San Juan Basin Royalty Properties located in Colorado are operated by BP. 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 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 $9,809,030 and $10,568,610 for the years 2006 and 2005, 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 14, 2007.

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 1 1⁄2% below the prime rate charged by The Bank of New York Trust Company, N.A., successor from JPMorgan Chase Bank, N.A., (as the successor by mergers to Texas Commerce Bank National Association) or the interest rate which The Bank of New York Trust Company, N.A., 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 is encouraged to 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 Treasury 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 (the 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 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 portfolio income. Subject to certain exceptions and transitional rules, royalty income cannot be offset by passive losses. 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 who 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 the 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 the 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 tax 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 exceeds one year at the time of sale or exchange. A long-term capital gains rate of 15% applies to most capital assets sold or exchanged 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 sale or exchange.

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, if applicable, at a lower treaty rate. 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 Code 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 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 may be 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 considerations. Therefore, each non-U.S. unitholder is encouraged to consult with his own tax adviser with respect to 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 taxable income. Each tax-exempt unitholder should consult its own advisor with respect to the treatment of royalty income.

DESCRIPTION OF ROYALTY PROPERTIES

Producing Acreage and Wells as of December 31, 2006

	Producing Acres(1)		**Producing Gas Wells(1)**	
	Gross	**Net**	**Gross**	**Net**
Hugoton Area (Kansas)	99,654	99,413	466	466
San Juan Basin (Northwestern New Mexico and Southwestern Colorado)	40,716	31,328	1,237	466
Total	140,370	130,741	1,703	932

(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 20% 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, including a few wells located in Southwestern Colorado, retained by ConocoPhillips represent approximately 80% 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 substantially all of 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. 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, 2006, 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 on Trust properties, 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 $18,400,000. The Trust s share of the total expenditures was approximately $2,400,000. 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 were made from 1990 until December 2006. The costs related to the San Juan Basin, Colorado portion were recovered in December 2004. However, subsequent earnings were not remitted to the Trust until December 2006. The cumulative earnings, including interest on undistributed earnings, reported to the Trust by the working interest owner through November 2006, totaled $1,280,412. In December, BP remitted $978,349 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings. BP communicated to the Trust this distribution represents all of the previously unpaid revenues. The Trustee is currently investigating the $302,063 difference in the original estimate of unpaid proceeds of $1,280,412 and the payment of $978,349.

Reserves

A study of the proved oil and gas reserves attributable to the Hugoton Royalty as of December 31, 2006 has been made by PNR. The following letter relating to the Reserves and Revenue as of December 31, 2006 From Certain Properties Owned by Mesa Royalty Trust (the Hugoton Reserve Report) beginning on page 8 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.

The following table summarizes (1) estimates of the Trust s net reserves as of December 31, 2006, and (2) the estimated future cash flow and present worth attributable to the Trust s 10.29282 percent net profits interest in certain San Juan Basin properties located in the state of New Mexico, administered by ConocoPhillips as of December 31, 2006, and is based on a reserve report prepared for the Trust by ConocoPhillips.

Trust Proved Reserves San Juan Basin Developed + Undeveloped	**Conventional Reservoirs**	**Fruitland Coal Reservoirs**	**Total All Reservoirs**
Natural Gas, MMcf	24,929	1,271	26,200
Condensate, Mbbl	86		86
Natural Gas Liquids, Mbbl	2,069		2,069

Trust Proved Reserves San Juan Basin Developed Only	**Conventional Reservoirs**	**Fruitland Coal Reservoirs**	**Total All Reservoirs**
Natural Gas, MMcf	23,595	1,271	24,866
Condensate, Mbbl	86		86
Natural Gas Liquids, Mbbl	2,061		2,061

Estimated Future Cash flow and Present Worth @ 10% ($000 s)	**Conventional Reservoirs**	**Fruitland Coal Reservoirs**	**Total All Reservoirs**
Future Cash Flow Before Federal Income Tax	$ 151,723	$ 5,124	$ 156,847
Present Worth at 10%	$ 53,500	$ 2,446	$ 55,946

Product prices used in the report for year-end 2006, which were based on product prices for the San Juan Basin effective December 31, 2006, were $4.30 per Mcf for conventional natural gas, $4.03 per Mcf for Fruitland Coal natural gas, $52.47 per barrel for condensate and $19.29 per barrel for natural gas liquids. Operating costs were $14,140 per completion per year for 619 net active completions of conventional gas wells during 2006, and $41,680 per completion per year for 54 net active completions of Fruitland Coal gas wells during 2006. Prices and operating costs were held constant over the life of the properties. Product prices excluded combined production and ad valorem taxes of 9.1 percent and 8.9 percent of revenue for Conventional and Fruitland Coal gas, respectively.

ConocoPhilips has informed the Trustee that its capital budget focus is increasing towards conventional reservoirs due to a depleting drilling inventory of 160-acre Fruitland Coal infill wells.

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.

April 2, 2007

Mesa Royalty Trust
Bank of New York (as Trustee)
919 Congress Ave., Ste. 500
Austin, TX 78701

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2006 of the extent and value of the proved natural gas liquids and natural gas 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, 2006. Net reserves are defined as that portion of the gross reserves attributable to the Trust interest after deducting royalties and other interest 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 interest 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, 2006, 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, 2006. In our preparation of the study, data available from wells drilled on the appraised properties through December 31, 2006 were used in estimating gross ultimate recovery. Gross production estimated to December 31, 2006 was deducted from gross ultimate recovery to arrive at the estimates of gross reserves as of December 31, 2006. 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 2006.

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.

Estimates of the net proved reserves attributable to the Trust, as of December 31, 2006, are as follows:

TOTAL PROVED RESERVES:	
Natural Gas (Mcf)	7,363,951
Natural Gas Liquids (bbl)	384,396
PROVED DEVELOPED RESERVES	
Natural Gas (Mcf)	7,363,951
Natural Gas Liquids (bbl)	384,396

Proved natural gas liquid 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 Prices - Natural gas liquids 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 2006 values and were not adjusted for inflation.

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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 ($)[1]	78,185,883
Future Lease Operating Expenses ($)	7,918,869
Future Net Production Taxes ($)	1,275,561
Future Net Ad Valorem Taxes ($)	4,459,118
Future Net Overhead Expense ($)	10,631,339
Future Capital Expenditures ($)	296,219
Future Net Cashflow ($)	53,604,777
Present Worth at 10 Percent ($)	25,139,834

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1. Future income tax expenses were not taken into account in the preparation of these estimates.

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 4-10(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.

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,

/s/ Paul McDonald
Paul McDonald
Vice President Domestic Reservoir Engineering

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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 made 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 $5.39 per Mcf for Hugoton properties and $4.29 per Mcf for San Juan Basin properties as of December 31, 2006) 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 2006 was $6.38 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 $70,000 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 49% of the Royalty income of the Trust during 2006.

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 2006, these purchasers included Greely Gas and Oneok Gas Marketing, 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, 2006 as compared to the year-ended December 31, 2005.

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, 2007. 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, 2006 through March 31, 2007, was 114.6 billion cubic feet of gas, compared with 122.1 billion cubic feet of gas during the same period last year.

San Juan Basin

Natural gas, oil, condensate and natural gas liquids produced from the San Juan Basin field and attributable to the Royalty accounted for approximately 51% of the Royalty income of the Trust during 2006. 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. Since 2000, demand for natural gas has increased while supplies from production have remained tight. Average annual wellhead prices generally increased from $1.55 per Mcf in 1995 to $2.32 per Mcf in 1997 then decreased to $1.96 per Mcf in 1998. Since 2000, these prices have been $3.69 per Mcf in 2000, $4.02 per Mcf in 2001, $2.95 per Mcf in 2002, $5.09 per Mcf in 2003, $5.49 per Mcf in 2004, $7.51 per MCF in 2005, and $6.42 per MCF in 2006 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 general, the FERC regulates the transportation of natural gas in interstate commerce by interstate pipelines. Over the course of approximately the previous decade, the FERC adopted regulations resulting in a restructuring of the natural gas industry. The principle elements of this restructuring were the requirement that interstate pipelines separate, or unbundle, into individual components the various services offered on their systems, with all transportation services to be provided on a non-discriminatory basis, and the prohibition against an interstate pipeline providing gas sales services except through separately-organized affiliates. In various rulemaking proceedings following its initial unbundling requirement, the FERC has refined its regulatory program applicable to interstate pipelines in various respects, and it has announced that it will continue to monitor these regulations to determine whether further changes are needed. As to these various developments, the working interest owners have advised the Trust that the on-going and evolving nature of these regulatory initiatives makes it impossible 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.

Item 1A. 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 and a material decrease in such prices could reduce the amount of Trust distributions. 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.

When natural gas prices decline, the Trust is affected two ways. First, net royalties are reduced. Second, exploration and development activity on the underlying properties may decline as some projects may become uneconomic and are either delayed or eliminated. 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 are being sold under short-term or multi-month contracts at market clearing prices or on the spot market.

Prior Litigation Against A Working Interest Owner Could Adversely Impact Distributable Income

As discussed in this Form 10-K under Legal Proceedings, PNR was party to a 1993 class action lawsuit. In August 2006, PNR informed the Trustee that it had reached an agreement to settle claims made in the lawsuit. PNR has advised the Trust that PNR s portion of the cash settlement for both 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 plantiffs continue to be paid for a royalty share of the helium) is approximately $32,700,000. PNR has advised the Trustee that the Trust s share of the settlement amount is to be paid in two payments of approximately $1,000,000 each. The first installment was paid on September 30, 2006 and an expected payment of approximately $900,000 is payable on September 30, 2007. The settlement agreement provides for adjustment to the manner in which royalty payments will be calculated and accordingly, PNR has advised the Trust it expects a small increase in the production costs beginning in 2007.

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. Production and development costs are impacted by increases in commodity prices both directly, through commodity-price dependent costs such as electricity, and indirectly, as a result of demand-driven increases in costs of oil field goods and services. 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 or too low.

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;
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures;
- the availability of enhanced recovery techniques; and
- relationships with landowners, working interest partners, pipeline companies and others.

Changes in these factors and assumptions can materially change reserve estimates and future net revenue 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 further complicated because the Trust holds an interest in the Royalty and does not own a specific percentage of the natural gas reserves. Ultimately, actual production, revenues and expenditures for the underlying properties, and therefore actual net proceeds payable to the Trust, will vary from estimates and those variations could be material. Results of drilling, testing and production after the date of those estimates may require substantial downward revisions or write-off of reserves.

The Trustee also relies entirely on reserve estimates and related information prepared by PNR and ConocoPhillips. While the Trustee has no reason to believe the reserve estimates included in this report are not accurate, to the extent additional information exists that could affect their reserve estimates, the estimated reserves in these reports could also be too low.

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

There are operational risks and hazards associated with the production and transportation of natural gas, including without limitation natural disasters, blowouts, explosions, fires, leakage of natural gas, releases of other hazardous materials, mechanical failures, cratering and pollution. Any of these or similar occurrences could result in the interruption or cessation of operations, personal injury or loss of life, property damage, damage to productive formations or equipment, damage to the environment of natural resources, or cleanup obligations. 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.

Terrorism and continued hostilities in the Middle East could decrease Trust distributions or the market price of the units of beneficial interest of the Trust.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism, the war in Iraq and other sustained military campaigns could adversely affect Trust distributions or the market price of the Units in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in natural gas prices, or the possibility that the infrastructure on which the operators developing the underlying properties rely could be a direct target or an indirect casualty of an act of terror.

The operators of the working interests 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. These regulations and changes in regulations could have a material adverse effect on Royalty income payable to the Trust.

Trust unitholders and the Trustee have no control over 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 failure of an operator to conduct its operations, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations, including environmental laws and regulations, in a proper manner could have an adverse effect on the net proceeds payable to the Trust.

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 Trustee relies upon the working interests owners for information regarding the Royalty Properties.

The Trustee relies on the working interest owners for information regarding the Royalty Properties. The working interest owners control (i) historical operating data, including production volumes, marketing of products, operating and capital expenditures, environmental and other liabilities, 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 related projections regarding production, operating expenses and capital expenses used in connection with the preparation of the reserve report, (iv) forward-looking information relating to production and drilling plans and (v) information regarding the Royalty Properties responsive to litigation claims. 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 Indenture, the Trustee is entitled to rely, and in fact relies, on certain experts in good faith. While the Trustee has no reason to believe its reliance on experts is unreasonable, this reliance on experts and limited access to information may be viewed as a weakness as compared to the management and oversight of entity forms other than trusts.

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 Business Description of the Units Federal Income Tax Matters under Item 1 of this Form 10-K.

Because the net proceeds payable to the Trust are derived from the sale of depleting assets, the portion of distributions to unitholders attributable to depletion may be considered a return of capital as opposed to a return on investment. Distributions that are a return of capital will ultimately diminish the depletion tax benefits available to the Trust unitholders, which could reduce the market value of the Trust units over time. Eventually, properties underlying the Trust s Royalty will cease to produce in commercial quantities and the Trust will, therefore, cease to receive any distributions of net proceeds therefrom.

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. Additionally, Trust unitholders have no voting rights in Pioneer or

ConcoPhillips. 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.

The limited liability of the Trust unitholders is uncertain.

The Trust unitholders are not protected from the liabilities of the Trust to the same extent that a shareholder would be protected from a corporation s liabilities. The structure of the Trust does not include the interposition of a limited liability entity such as a corporation or a limited partnership which would provide further limited liability protection to Trust unitholders. While the Trustee is liable for any excess liabilities incurred if the Trustee fails to insure that such liabilities are to be satisfied only out of Trust assets, under the laws of Texas, which are unsettled on this point, a holder of units may be jointly and severally liable for any liability of the Trust if the satisfaction of such liability was not contractually limited to the assets of the Trust and the assets of the Trust and the trustee are not adequate to satisfy such liability. As a result, Trust unitholders may be exposed to personal liability.

Item 1B. Unresolved Staff Comments.

There were no unresolved Securities and Exchange Commission comments as of December 31, 2006.

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, in August 2006, PNR informed the Trustee that it had reached an agreement to settle claims made in the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.,* which was filed in the 26th Judicial District Court, Stevens County, Kansas. The plaintiffs in this lawsuit are royalty owners in oil and gas properties located in the Hugoton field, which are owned by Pioneer USA, a subsidiary of Pioneer Natural Resources Company (Pioneer). The plaintiffs sued a predecessor company to Pioneer USA asserting various claims relating to alleged improper deductions in the calculation of royalties.

Under the terms of the agreement, Pioneer USA will make cash payments to settle the plaintiffs claims with respect to production occurring on and before December 31, 2005. Pioneer USA also agreed to adjust the manner in which royalty payments to the class members will be calculated for production occurring on and after January 1, 2006.

Pioneer s portion of the cash payment is expected to be approximately $32,700,000. Pioneer will pay the cash portion in two installments. Pioneer has advised the Trustee that the portion of the cash payments net to the Trust s interest was approximately $1,000,000 paid on September 30, 2006 and is currently expected to be approximately $900,000 payable on September 30, 2007. Pioneer USA will initially pay the costs attributable to the Trust s interest but will recover these costs through payments out of future gross proceeds on the Trust s properties. The $1,000,000 attributable to the Trust paid on September 30, 2006, was deducted from royalty income in 2006 and the $900,000 anticipated to be paid on September 30, 2007, will be deducted from the Trust s future royalty income. Accordingly, royalty income to the Trust will be significantly reduced until all of these payments, together with any applicable interest as provided under the overriding royalty conveyance of the Trust s properties, are recouped by Pioneer USA.

Pioneer has advised the Trust that under the terms of the settlement agreement, the amounts required to be paid will be reduced if potential participating class members elect not to participate in the settlement by opting out under procedures established by the court. The settlement agreement contains a refund mechanism to address the circumstance where potential participating parties opt out after one of the funding installments is made. Pioneer cannot predict whether opt-outs will occur, or in what magnitude, but in the event that opt-outs occur triggering a refund, Pioneer will advise us of the refund amount attributable to the Trust.

The Trustee has been advised by ConocoPhillips that it is subject to litigation in the ordinary course of business for certain matters that include the Royalty Properties. While the working interest owner has advised the Trustee that it does not currently believe any of the pending litigation will have a material adverse effect net to the Trust, in the event such matters were adjudicated or settled in a material amount and charges were made against Royalty income, such charges could have a material impact on future Royalty income.

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 2006.

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PART II

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

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, 2006 and December 31, 2005, were as follows:

	2006			2005		
Quarter	**High**	**Low**	**Distribution**	**High**	**Low**	**Distribution**
First	$ 69.55	$ 64.50	$ 1.9136	$ 68.20	$ 58.65	$ 1.3537
Second	$ 68.40	$ 60.00	$ 1.3216	$ 67.85	$ 62.85	$ 1.1958
Third	$ 65.90	$ 50.26	$ 1.0784	$ 72.25	$ 64.00	$ 1.2809
Fourth	$58.10	$ 48.12	$ 0.9295	$ 73.70	$ 66.75	$ 1.8161

At April 2, 2007, the 1,863,590 units outstanding were held by 1,022 unitholders of record.

Item 6. Selected Financial Data.

	2006	**2005**	**2004**	**2003**	**2002**
Royalty income	$ 9,809,030	$ 10,568,610	$ 8,855,234	$ 9,299,034	$ 4,841,115
Distributable income	$ 9,771,034	$ 10,522,777	$ 8,814,499	$ 9,265,740	$ 4,814,201
Distributable income per unit	$ 5.2431	$ 5.6465	$ 4.7298	$ 4.9720	$ 2.5893
Total assets at year end	$ 9,834,998	$ 11,905,561	$ 11,322,309	$ 11,711,640	$ 11,431,621

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 Business 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 2006 and 2005

	Years Ended December 31,	
	2006	**2005**
Royalty income	$ 9,809,030	$ 10,568,610
Interest income	30,275	17,780
General and administrative expenses	(68,271)	(63,613)
Distributable income	$ 9,771,034	$ 10,522,777
Distributable income per unit	$ 5.2431	$ 5.6465

The Trust s Royalty income was $9,809,030 in 2006, a decrease of approximately 7% as compared to $10,568,610 in 2005, primarily as a result of capital spending in 2006.

Royalty income from the Hugoton Royalty Properties was $4,810,684 in 2006, a decrease of approximately 12%, as compared to $5,441,802 million in 2005, primarily as a result of payments made of approximately $1,000,000 to partially settle claims made in the John Steven Alford and Robert Larrabee v. Pioneer lawsuit discussed in Item 3. Legal Proceedings of this Form 10-K.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $7.48 per Mcf and $42.83 per barrel, respectively, in 2006 as compared to $6.62 per Mcf and $34.44 per barrel, respectively, in 2005. Net production attributable to the Hugoton Royalty was 406,409 Mcf of natural gas and 41,344 barrels of natural gas liquids in 2006 as compared with 591,015 Mcf of natural gas and 44,404 barrels of natural gas liquids in 2005. Actual production volumes attributable to the Hugoton properties were 739,168 Mcf of natural gas and 41,363 barrels of natural gas liquids in 2006 as compared with 786,935 Mcf of natural gas and 44,425 barrels of natural gas liquids in 2005.

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 $4,019,997 in 2006 as compared to $5,126,808 in 2005, a decrease of 22%. The decrease in Royalty income was due to decreased natural gas and natural gas liquids volumes in 2006 as well as, increased capital expenditures. Royalty income from the San Juan Basin Properties located in the state of Colorado was $978,349 in 2006 as compared to $0 in 2005. The San Juan Basin Royalty Properties located in the state of Colorado recouped all costs related to the Fruitland Coal drilling program as of December 2004. However, subsequent earnings were not remitted to the Trust until December 2006. The cumulative earnings, including interest on undistributed earnings, reported to the Trust by BP through November 2006, totaled approximately $1,280,000. In December, BP remitted approximately $978,000 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings. The working interest owner communicated to the Trust this distribution represents all of the previously unpaid revenues. The Trustee is currently investigating the $251,000 difference in the original estimate of unpaid proceeds of approximately $1,229,000 and the payment of approximately $978,000.

The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty properties located in the state of New Mexico was $6.37 per Mcf and $40.34 per barrel, respectively, in 2006 compared with $6.24 per Mcf and $34.37 per barrel, respectively, in 2005. Net production attributable to the San Juan Basin Royalty located in the state of New Mexico was 374,180 Mcf of natural gas and 40,567 barrels of natural gas liquids, oil and condensate in 2006 as compared to 589,652 Mcf of natural gas and 42,112 barrels of natural gas liquids, oil and condensate in 2005. Actual production volumes attributable to the San Juan Basin properties located in the state of New Mexico was 928,364 Mcf of natural gas and 48,046 barrels of natural gas liquids, oil and condensate in 2006 as compared with 1,038,065 Mcf of natural gas and 51,331 barrels of natural gas liquids, oil and condensate in 2005.

The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty properties located in the state of Colorado was $4.38 per Mcf in 2006. Net production attributable to the San Juan Basin Royalty properties located in the state of Colorado was 223,367 Mcf of natural gas in 2006. As described above, there were no earnings remitted to the Trust in 2005 related to the San Juan Royalty properties located in the state of Colorado.

Years 2005 and 2004

	Years Ended December 31,	
	2005	**2004**
Royalty income	$ 10,568,610	$ 8,855,234
Interest income	17,780	10,823
General and administrative expenses	(63,613)	(51,558)
Distributable income	$ 10,522,777	$ 8,814,499
Distributable income per unit	$ 5.6465	$ 4.7298

The Trust s Royalty income was $10,568,610 in 2005, an increase of approximately 19% as compared to $8,855,234 in 2004, primarily as a result of higher prices of natural gas in 2005.

Royalty income from the Hugoton Royalty Properties was $5,441,802 in 2005, an increase of approximately 13%, as compared to $4,821,361 in 2004, primarily as a result of higher prices of natural gas in 2005.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $6.62 per Mcf and $34.44 per barrel, respectively, in 2005 as compared to $5.28 per Mcf and $25.50 per barrel, respectively, in 2004. Net production attributable to the Hugoton Royalty was 591,015 Mcf of natural gas and 44,404 barrels of natural gas liquids in 2005 as compared with 675,120 Mcf of natural gas and 49,359 barrels of natural gas liquids in 2004. Actual production volumes attributable to the Hugoton properties were 786,935 Mcf of natural gas and 44,425 barrels of natural gas liquids in 2005 as compared with 892,353 Mcf of natural gas and 49,391 barrels of natural gas liquids in 2004.

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 $5,126,808 in 2005 as compared to $4,033,873 in 2004, an increase of 27%. The increase in Royalty income was due to increased natural gas and natural gas liquids prices in 2005. No Royalty income was received from the San Juan Basin Royalty Properties located in the state of Colorado in 2005 or 2004 other than a few wells retained by ConocoPhillips. Although, the Colorado properties have recouped all costs related to the Fruitland Coal drilling program as of December 2004, BP as the operator did not remit cumulative earnings of $582,849 to the Trust. Since Mesa Royalty Trust is a cash basis entity, the $543,989 and $38,860 cannot be recognized as income for the years ended December 31, 2005 and 2004, respectively.

The average price received for natural gas and natural gas liquids, oil and condensate from the San Juan Basin Royalty properties was $6.24 per Mcf and $34.37 per barrel, respectively, in 2005 compared with $4.64 per Mcf and $26.14 per barrel, respectively, in 2004. Net production attributable to the San Juan Basin Royalty was 589,652 Mcf of natural gas and 42,112 barrels of natural gas liquids, oil and condensate in 2005 as compared to 622,950 Mcf of natural gas and 43,741 barrels of natural gas liquids, oil and condensate in 2004. Actual production volumes attributable to the San Juan Basin properties was 1,038,065 Mcf of natural gas and 51,331 barrels of natural gas liquids, oil and condensate in 2005 as compared with 1,070,437 Mcf of natural gas and 55,890 barrels of natural gas liquids, oil and condensate in 2004.

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

	Hugoton		San Juan New Mexico		Colorado		Total	
	Natural Gas	Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids
Year ended December 31, 2006:								
The Trust's proportionate share of								
Gross Proceeds(1)	$ 5,527,968	$ 1,770,745	$ 5,915,794	$ 1,937,941	$ 1,550,429	$	$ 12,994,191	$ 3,708,686
Less the Trust's proportionate share of								
Capital costs recovered(2)	(217,180)		(1,205,870)				(1,423,050)	
Operating costs	(2,270,849)		(2,326,396)	(301,472)	(270,017)		(4,867,262)	(301,472)
Withheld revenues(3)					(302,063)		(302,063)	
Royalty Income	$ 3,039,939	$ 1,770,745	$ 2,383,528	$ 1,636,469	$ 978,349	$	$ 6,401,816	$ 3,407,214
Average Sales Price	$ 7.48	$ 42.83	$ 6.37	$ 40.34	$ 4.38	$	$ 6.38	$ 41.58
Net production volumes attributable to the Royalty	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
paid(4)	406,409	41,344	374,180	40,567	223,367		1,003,956	81,911
Year ended December 31, 2005:								
The Trust's proportionate share of								
Gross Proceeds(1)	$ 5,203,899	$ 1,529,284	$ 7,388,469	$ 1,764,397	$	$	$ 12,592,368	$ 3,293,681
Less the Trust's proportionate share of								
Capital costs recovered(2)	(160,042)		(693,556)				(853,598)	
Operating costs	(1,131,339)		(2,471,497)	(317,016)			(3,602,836)	(317,016)
Withheld revenues(3)			(543,989)				(543,989)	
Royalty Income	$ 3,912,518	$ 1,529,284	$ 3,679,427	$ 1,447,381	$	$	$ 7,591,945	$ 2,976,665
Average Sales Price	$ 6.62	$ 34.44	$ 6.24	$ 34.37	$	$	$ 6.43	$ 34.41
Net production volumes attributable to the Royalty	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
paid(4)	591,015	44,404	589,652	42,112			1,180,707	86,506
Year ended December 31, 2004:								
The Trust's proportionate share of								
Gross Proceeds(1)	$ 4,707,717	$ 1,258,655	$ 5,499,710	$ 1,461,209	$	$	$ 10,207,427	$ 2,719,864
Less the Trust's proportionate share of								
Capital costs recovered(2)	(103,035)		(634,318)				(737,353)	
Operating costs	(1,041,976)		(1,927,715)	(317,826)			(2,969,691)	(317,826)
Interest on Carryforward			(8,327)				(8,327)	
Withheld revenues(3)			(38,860)				(38,860)	
Royalty Income	$ 3,562,706	$ 1,258,655	$ 2,890,490	$ 1,143,383	$	$	$ 6,453,196	$ 2,402,038
Average Sales Price	$ 5.28	$ 25.50	$ 4.64	$ 26.14	$	$	$ 4.97	$ 25.80
Net production volumes attributable to the Royalty	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
paid(4)	674,755	49,359	622,950	43,741			1,298,430	93,102

(1) Gross Proceeds from natural gas liquids attributable to the Hugoton and San Juan Basin Properties are net of a volumetric in-kind processing fee retained by PNR and ConocoPhillips, respectively.

(2) Capital costs recovered represents capital costs incurred during the current or prior periods to the extent that such costs have been recovered by the 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.

(3) The Colorado portion of the San Juan Basin Royalty properties recouped all costs related to the Fruitland Coal drilling program as of December 2004. However, subsequent cumulative earnings were not remitted to the Trust until December 2006. The cumulative earnings reported to the Trust by the working

interest owner from January 2005 through October 2006 totaled approximately $1,280,000. In December, BP remitted approximately $978,000 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings. Since Royalty income for the Trust is recorded on a cash basis, Royalty income for year ended December 31, 2005 and 2004 of $543,989 and $38,860, respectively, was not recognized until the year ended December 31, 2006.

(4) Net production volumes attributable to the Royalty are determined by dividing Royalty income by the average sales price received.

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, 2006	2005	2004
Royalty income	$ 9,809,030	$ 10,568,610	$ 8,855,234
Interest income	30,275	17,780	10,823
General and administrative expenses	(68,271)	(63,613)	(51,558)
Distributable income	$ 9,771,034	$ 10,522,777	$ 8,814,499
Distributable income per unit	$ 5.2431	$ 5.6465	$ 4.7298

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31, 2006	2005
ASSETS		
Cash and short-term investments	$ 1,725,732	$ 3,378,013
Interest receivable	6,551	6,280
Net overriding royalty interests in oil and gas properties	42,498,034	42,498,034
Less: accumulated amortization	(34,395,319)	(33,976,766)
Total assets	$ 9,834,998	$ 11,905,561
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 1,732,283	$ 3,384,293
Trust corpus (1,863,590 units of beneficial interest authorized and outstanding)	8,102,715	8,521,268
Total liabilities and trust corpus	$ 9,834,998	$ 11,905,561

STATEMENTS OF CHANGES IN TRUST CORPUS

	Years Ended December 31, 2006	2005	2004
Trust corpus, beginning of year	$ 8,521,268	$ 9,017,067	$ 9,547,692
Distributable income	9,771,034	10,522,777	8,814,499
Distributions to unitholders	(9,771,034)	(10,522,777)	(8,814,499)
Amortization of net overriding royalty interests	(418,553)	(495,799)	(530,625)
Trust corpus, end of year	$ 8,102,715	$ 8,521,268	$ 9,017,067

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 Company (BP) a subsidiary of BP p.l.c. 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. As used in the notes to financial statements, 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 refers to the operator of the Colorado San Juan Basin Royalty Properties unless otherwise indicated.

Effective October 2, 2006, the Bank of New York Trust Company, N.A. (the Trustee) succeeded JPMorgan Chase Bank, N.A. as Trustee of the Trust. JPMorgan Chase Bank, N.A. 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 (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.

MESA ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS (Continued)

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

MESA ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS (Continued)

(6) PNR Legal Proceedings

There are no pending legal proceedings to which the Trust is a named party. However, in August 2006, PNR informed the Trustee that it had reached an agreement to settle claims made in the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.,* which was filed in the 26th Judicial District Court, Stevens County, Kansas. The plaintiffs in this lawsuit are royalty owners in oil and gas properties located in the Hugoton field, which are owned by Pioneer USA, a subsidiary of Pioneer Natural Resources Company (Pioneer). The plaintiffs sued a predecessor company to Pioneer USA asserting various claims relating to alleged improper deductions in the calculation of royalties.

Under the terms of the agreement, Pioneer USA will make cash payments to settle the plaintiffs claims with respect to production occurring on and before December 31, 2005. Pioneer USA also agreed to adjust the manner in which royalty payments to the class members will be calculated for production occurring on and after January 1, 2006.

Pioneer s portion of the cash payment is expected to be approximately $32,700,000. Pioneer will pay the cash portion in two installments. Pioneer has advised the Trustee that the portion of the cash payments net to the Trust s interest was approximately $1,000,000 paid on September 30, 2006 and an expected payment of approximately $900,000 payable on September 30, 2007. Pioneer USA will initially pay the costs attributable to the Trust s interest but will recover these costs through payments out of future gross proceeds on the Trust s properties. The $1,000,000 attributable to the Trust paid on September 30, 2006, was deducted from royalty income in 2006 and the $900,000 anticipated to be paid on September 30, 2007, will be deducted from the Trust s future royalty income. Accordingly, royalty income to the Trust will be significantly reduced until all of these payments, together with any applicable interest as provided under the overriding royalty conveyance of the Trust s properties, are recouped by Pioneer USA.

Pioneer has advised the Trust that under the terms of the settlement agreement, the amounts required to be paid will be reduced if potential participating class members elect not to participate in the settlement by opting out under procedures established by the court. The settlement agreement contains a refund mechanism to address the circumstance where potential participating parties opt out after one of the funding installments is made. Pioneer cannot predict whether opt-outs will occur, or in what magnitude, but in the event that opt-outs occur triggering a refund, Pioneer will advise us of the refund amount attributable to the Trust.

(7) Supplemental Reserve Information (Unaudited)

Estimates of the proved oil and gas reserves attributable to the Hugoton Royalty Properties as of December 31, 2006, 2005 and 2004 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 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

MESA ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS (Continued)

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

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

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.

MESA ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS (Continued)

(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, 2003	2,540,378	31,440,927
Revisions to previous estimates	(36,084)	(976,163)
Extensions, discoveries and other additions		
Production	(93,100)	(1,298,070)
December 31, 2004	2,411,194	29,166,694
Revisions to previous estimates	36,322	2,685,788
Extensions, discoveries and other additions		
Production	(86,516)	(1,180,667)
December 31, 2005	2,361,000	30,671,815
Revisions to previous estimates	260,345	3,896,093
Extensions, discoveries and other additions		
Production	(81,949)	(1,003,957)
December 31, 2006	2,539,396	33,563,951
Proved Developed Reserves:		
December 31, 2003	2,487,378	30,953,927
December 31, 2004	2,346,194	28,501,694
December 31, 2005	2,361,000	29,961,815
December 31, 2006	2,531,396	32,229,951

- 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: 2006, 86,000 Bbls; 2005, 68,000 Bbls; and 2004, 63,000 Bbls.

- The Hugoton Royalty represents 15%, 23%, and 24% of the estimated proved oil, condensate and natural gas liquids reserves and 31%, 31%, and 36% of the estimated proved natural gas reserves as of December 31 of 2006, 2005 and 2004, respectively.

MESA ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS (Continued)

(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, 2006 (In thousands)	2005	2004
The Trust s proportionate share of future gross proceeds	$ 277,063	$ 456,388	$ 328,533
Less the Trust s proportionate share of Future operating costs	(59,343)	(131,976)	(103,173)
Future capital costs	(7,268)	(2,983)	(3,187)
Future royalty income	210,452	321,429	222,173
Discount at 10% per annum	(129,366)	(195,407)	(130,044)
Standardized measure of future royalty income from proved oil and gas reserves	$ 81,086	$ 126,022	$ 92,129

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

	December 31, 2006 (In thousands)	2005	2004
Standardized measure at beginning of year	$ 126,022	$ 92,129	$ 91,762
Revisions of previous estimates	1,033	(2,214)	(8,338)
Net changes in price and production costs	(48,762)	37,462	8,385
Extensions, discoveries and other additions			
Royalty income	(9,809)	(10,568)	(8,855)
Accretion of discount	12,602	9,213	9,176
Net changes in standardized measure	(44,936)	33,893	368
Standardized measure at end of year	$ 81,086	$ 126,022	$ 92,129

- The Hugoton Royalty represents approximately 47% and 35% of the standardized measure of future royalty income for 2006 and 2005, respectively.

- Standardized measure at December 31, 2006 was calculated using natural gas prices of $5.39 per Mcf for Hugoton properties and $4.29 per Mcf for San Juan properties.

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MESA ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS (Continued)

(8) Selected Quarterly Financial Data (Unaudited)

	Summarized Quarterly Results Three Months Ended March 31	June 30	September 30	December 31
2006:				
Royalty income	$ 3,580,350	$ 2,472,887	$ 2,022,637	$ 1,733,156
Distributable income	$ 3,566,247	$ 2,462,899	$ 2,009,605	$ 1,732,283
Distributable income per unit	$ 1.9136	$ 1.3216	$ 1.0784	$ 0.9295
2005:				
Royalty income	$ 2,539,241	$ 2,244,561	$ 2,396,815	$ 3,387,993
Distributable income	$ 2,522,852	$ 2,228,498	$ 2,387,134	$ 3,384,293
Distributable income per unit	$ 1.3538	$ 1.1958	$ 1.2809	$ 1.8160

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

**The Bank of New York Trust Company, N.A., Trustee
and the Unit Holders of Mesa Royalty Trust:**

We have audited the accompanying statements of assets, liabilities and trust corpus of Mesa Royalty Trust as of December 31, 2006 and 2005, and the related statements of distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2006. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

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

As described in Note 3, these financial statements were prepared on the basis of cash receipts and disbursements as prescribed by the Securities and Exchange Commission, 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 Mesa Royalty Trust as of December 31, 2006 and 2005, and the distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2006, in conformity with the basis of accounting described in Note 3.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Mesa Royalty Trust s internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated April 2, 2007 expressed an unqualified opinion on the Trustee s assessment of, and the effective operation of, internal control over financial reporting.

KPMG LLP

Houston, Texas
April 2, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Bank of New York Tust Company, N.A., Trustee
and the Unit Holders of Mesa Royalty Trust

We have audited the Trustee s assessment, included in the accompanying report, *The Trustee s Report on Internal Control over Financial Reporting,* that Mesa Royalty Trust (the Trust) maintained effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trustee is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on the Trustee s assessment and an opinion on the effectiveness of the Trust s internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Trustee s assessment that Mesa Royalty Trust maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Also in our opinion, Mesa Royalty Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the accompanying statements of assets, liabilities and trust corpus of Mesa Royalty Trust as of December 31, 2006 and 2005, and the related statements of distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2006, and our report dated April 2, 2007 expressed an unqualified opinion on those financial statements.

KPMG LLP

Houston, Texas
April 2, 2007

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 The Bank of New York Trust Company, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust s periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the Trustee carried out an evaluation of the Trustee s disclosure controls and procedures. Mike Ulrich, as Trust Officer of the Trustee, has concluded that such controls and procedures are effective.

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, the Trustee relies on information provided by the working interest owners, including (i) the status of litigation, (ii) historical operating data, plans for future operating and capital expenditures and reserve information, (iii) information relating to projected production; and (iv) conclusions regarding reserves by their internal reserve engineers or other experts in good faith. See Item 1A Risk Factors Trust unitholders and the Trustee have no control over the operation or development of the Royalty Properties and have little influence over operation or development and The Trustee relies upon the working interest owners for information regarding the Royalty Properties in this Form 10-K for a description of certain risks relating to these arrangements and reliance.

Trustee s Report on Internal Control over Financial Reporting. The Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities and Exchange Act of 1934, as amended. The Trustee conducted an evaluation of the effectiveness of the Trust s internal control over financial reporting (internal control over financial reporting) based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Trustee s evaluation under the framework in *Internal Control-Integrated Framework,* the Trustee concluded that the Trust s internal control over financial reporting was effective as of December 31, 2006. The Trustee s assessment of the effectiveness of the Trust s internal control over financial reporting as of December 31, 2006 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which is included herein.

The Trustee does not expect that the Trustee s disclosure controls and procedures relating to the Trust or the Trustee s internal control over financial reporting relating to the Trust will prevent all errors and all fraud. A registrant s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A registrant s internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the registrant; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the modified basis of accounting discussed above, and that receipts and expenditures of the registrant are being made only in accordance with authorizations of management and directors of the registrant; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the registrant s assets that could have a material effect on the financial statements.

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

Further, the design of disclosure controls and procedures and internal control over financial reporting must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected.

Changes in Internal Control over Financial Reporting. In connection with the evaluation by the Trustee of changes in internal control over financial reporting of the Trust that occurred during the Trust s last fiscal quarter, no change in the Trust s internal control over financial reporting was identified that has materially affected, or is reasonably likely to materially affect, the Trust s internal control over financial reporting. The Trustee notes for purposes of clarification that it has no authority over, has not evaluated and makes no statement concerning, the internal control over financial reporting of the working interest owners.

Item 9B. *Other Information.*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

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 hoders of a majority of the outstanding units 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.

However, employees of the Trustee must comply with the bank s code of ethics. The Trust does not have a board of directors, and therefore does not have an audit committee, an audit committee financial expert, or a nominating committee.

Item 11. *Executive Compensation.*

Not applicable.

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

(a) Security Ownership of Certain Beneficial Owners.

Based on filings with the Securities and Exchange Commission on Schedules 13D and 13G, as of March 14, 2007 there were no owners of units in excess of 5% of the outstanding units.

(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, Director Independence.*

Not applicable.

Item 14. *Principal Accounting Fees and Services.*

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional 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 2006 and 2005 and fees billed for other services rendered by KPMG LLP.

	2006	2005
Audit fees (1)	$ 285,000	$ 215,000
Audit-related fees		
Tax fees (2)	40,000	40,000
All other fees		
Total fees	$ 325,000	$ 255,000

(1) Audit fees consist of fees for the audit of the Mesa Royalty Trust financial statements, internal control over financial reporting 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 2006 related to 2005 tax work and in 2005 for 2004 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.*

(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 The Bank of New York Trust Company, N.A. is the successor trustee to JPMorgan Chase Bank, N.A. JP Morgan Chase Bank, N.A. 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		

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	THE BANK OF NEW YORK TRUST COMPANY, N.A., TRUSTEE
By:	/s/ MIKE ULRICH Mike Ulrich *Vice President & Trust Officer*

April 2, 2007

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

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