MESA ROYALTY TRUST/TX
Form 10-K
March 16, 2010

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ý **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2009**

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	**76-6284806**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A., Trustee 919 Congress Avenue, Austin, Texas	**78701**
(Address of principal executive offices)	(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 ý

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 ý

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 ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark 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. ý

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

Large accelerated filer o	Accelerated filer ý	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller Reporting Company o

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

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, 2009 of $26.88 was approximately $50,093,299.

As of March 12, 2010, 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.

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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 Mellon 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 Mellon 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. On that date, Mesa Petroleum Co. predecessor to Mesa Limited Partnership ("MLP"), which was the predecessor to Mesa Inc., conveyed to the Trust an overriding royalty interest (the "Royalty") equal to 90% of the Net Proceeds (as defined in the Conveyance and described below) attributable to the specified interests in properties conveyed by the assignor on that date (the "Subject Interests"). The Subject Interests consisted of interests in certain 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"). The Royalty is evidenced by counterparts of an Overriding Royalty Conveyance dated as of November 1, 1979 (the "Conveyance"). 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. Substantially all of the San Juan Basin Royalty Properties located in New Mexico are operated by ConocoPhillips. Effective January 1, 2005, ConocoPhillips assigned its interest in an immaterial number of San Juan Basin Royalty Properties located in New Mexico to XTO Energy Inc. 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 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. 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 by 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 two successive years is less than $250,000 per year or (ii) a vote by the unitholders in favor of termination. Royalty income of the Trust was $4,052,357 and $13,845,456 for the years 2009 and 2008, 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 Conveyance, the Trust is entitled to payment of 90% of the Net Proceeds (as defined in the Conveyance), realized from Subject Minerals (as defined in the Conveyance), 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" is defined in the Conveyance as the excess of Gross Proceeds, received by the working interest owners during a particular period over operating and capital costs for such period. "Gross Proceeds" is defined in the Conveyance as the amount received by the working interest owners from the sale of Subject Minerals, subject to certain adjustments. Subject Minerals mean all oil, gas and other minerals, whether similar or dissimilar, in and under, and which may be produced, saved and sold from, and which accrue and are attributable to, the Subject Interests from and after November 1, 1979. 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 and the Trust conveyed to an affiliate of Mesa Petroleum Co. 88.5571% of the original Royalty (such transfer, the "1985 Assignment"). The effect of the 1985 Assignment was an overall reduction of approximately

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88.56% in the size of the Trust, distributable income and related Trust reserves, effective April 1, 1985. See Note 2 in the Notes to Financial Statements under Item 8 of this Form 10-K.

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

DESCRIPTION OF THE UNITS

Each unit is evidenced by a transferable certificate issued by the Trustee. Each unit ranks equally for purposes of distributions and has one vote on any matter submitted to unitholders. A total of 1,863,590 units were outstanding at March 12, 2010.

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 Mellon Trust Company, N.A., successor from JPMorgan Chase Bank, N.A., (as the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association) or the interest rate which The Bank of New York Mellon 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

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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. As a grantor trust, the Trust incurs no federal income tax liability and each unitholder is subject to tax on the unitholder's pro rata share of the income and expense of the Trust as if the unitholder were the direct owner of a pro rata share of the Trust's assets.

The Trustee assumes that some Trust Units are held by a middleman, as such term is broadly defined in U.S. Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. The Bank of New York Mellon Trust Company, N.A., 919 Congress Avenue, Austin, Texas 78701, telephone number 1-800-852-1422, is the representative of the Trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT. Unitholders whose units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the units.

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.

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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. The long-term capital gain rate applicable to most capital assets with a holding period of more than one year is 15%, but that rate is currently scheduled to expire December 31, 2010. Without Congressional action, for taxable years beginning on or after January 1, 2011, the long-term capital gain rate is scheduled to increase to 20%. 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 (without taking into account any deductions, such as depletion) 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 is encouraged to consult its own advisor with respect to the treatment of royalty income.

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DESCRIPTION OF ROYALTY PROPERTIES

Producing Acreage and Wells as of December 31, 2009

	Producing Acres(1)		Producing Gas Wells(1)	
	Gross	Net	Gross	Net
Hugoton Area (Kansas)	99,654	99,413	469	468
San Juan Basin (Northwestern New Mexico and Southwestern Colorado)	40,716	31,328	1,237	466
Total	140,370	130,741	1,706	934

(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 40% 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 Trustee has been informed that approximately 4,160 acres applicable to the Hugoton Royalty Properties are undeveloped.

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 overseeing oil and gas operations in the state of Kansas. Hugoton field gas is also affected by 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. PNR completed the sale of its underlying interest in the San Juan Basin Royalty Properties to ConocoPhillips on April 30, 1991. The San Juan Basin New Mexico reserves, including a few wells located in Southwestern Colorado, retained by ConocoPhillips represent approximately 53% 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. 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. Effective January 1, 2005, ConocoPhillips assigned its interest in an immaterial number of San Juan Basin Royalty Properties located in New Mexico to XTO Energy Inc. See " Description of the Trust" under Item 1 of this Form 10-K. The San Juan Basin Royalty Properties located in Colorado account for approximately 7% 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

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acres and 25,400 net acres with Fruitland Coal potential. The working interest owner has advised the Trust that, as of December 31, 2009, 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 and July 2007. 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 2006, BP remitted $978,349 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings for the San Juan properties it operates. In July 2007, Red Willow remitted $159,497 for payment of undistributed earnings from January 2005 through December 2006 for the properties it operates. BP communicated to the Trust that these distributions represent all of the previously unpaid revenues. The Trustee does not expect to receive any further distributions relating to this issue.

Drilling

There were no exploratory wells drilled on the Royalty Properties during 2009, 2008 and 2007. Less than one net developmental well has been drilled on the Royalty Properties in each of 2009, 2008 and 2007, all of which were productive.

Reserves

Modernization of Oil and Gas Reporting Requirements

Effective for fiscal years ending on or after December 2009, the SEC approved revisions designed to modernize the oil and gas company reserve reporting requirements. The most significant amendments to the requirements include the following:

- commodity prices economic producibility of reserves and discounted cash flows will be based on a 12-month average commodity price unless contractual arrangements designate the price to be used;

- disclosure of unproved reserves probable and possible reserves may be disclosed separately on a voluntary basis;

- proved undeveloped reserve guidelines reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered;

- reserve estimation using new technologies reserves may be estimated through the use of reliable technology in addition to flow tests and production history; and

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nontraditional resources the definition of oil and gas producing activities will expand and focus on the marketable product rather than the method of extraction.

Proved Reserves

A study of the proved Hugoton Area and San Juan Basin oil and gas reserves attributable to the Trust has been made by DeGolyer and MacNaughton, independent petroleum engineering consultants, as of December 31, 2009. A copy of this Reserve Report has been filed as an exhibit to this annual report on Form 10-K. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Calgary, and Moscow. The firm's more than 100 professionals include engineers, geologists, geophysicists, petrophysicists, and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies, and equity studies related to the domestic and international energy industry. These services have been provided for over 70 years. DeGolyer and MacNaughton restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas, or mineral properties, or securities or notes of clients. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. In serving the petroleum industry and financial community, the firm's experienced staff provides knowledge, independent judgment, integrity, and confidential service to its clients. The firm is a Texas Registered Engineering Firm, No. F-716.

The Senior Vice President at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the reserve estimates is a Registered Petroleum Engineer in the State of Texas with more than 35 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1974 and he is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists.

The Hugoton Area and San Juan Basin Reserve Report reflects estimated production, reserve quantities and future net revenue based upon estimates of the future timing of actual production without regard to when received in cash by the Trust, which differs from the manner in which the Trust recognizes and accounts for its Royalty income.

Estimates of the gross and net proved reserves, as of December 31, 2009, of the Trust's ownership in the overriding royalty interest are presented below. Total liquid reserves (condensate plus natural gas liquids) are expressed in thousands of barrels (Mbbl) and gas reserves are expressed in thousands of cubic feet (Mccf).

	Net Reserves					
	BP	**Conoco**	**Pioneer**	**Red Willow**	**XTO**	**Total**
Proved Developed						
Oil and Natural Gas Liquids, Mbbl	0	315	162	0	2	479
Gas, Mccf	315	3,539	2,849	53	17	6,773
Proved Undeveloped						
Oil and Natural Gas Liquids, Mbbl	0	0	6	0	0	6
Gas, Mccf	0	0	106	0	0	106
Total, Proved						
Oil and Natural Gas Liquids, Mbbl	0	315	168	0	3	485
Gas, Mccf	315	3,540	2,955	53	27	6,879

The estimated future net revenue and standardized measure of future net royalty income discounted at 10 percent attributable to the Trust's overriding royalty interest as of December 31, 2009, under the economic assumptions furnished by the working interest owners is summarized as follows, expressed in thousands of dollars:

	BP	Conoco	Pioneer	Red Willow	XTO	Total
Future Net Revenue(1)	497	16,193	14,164	104	63	31,021

	BP	Conoco	Pioneer	Red Willow	XTO	Total
Standardized Measure of Future Net Royalty Income discounted at 10%(1)	323	8,932	8,455	60	40	17,810

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

Please read "Summary Reserve Report from DeGolyer and MacNaughton" attached hereto as Exhibit 99 for more information.

The Reserve Report was delivered to the Trustee on March 15, 2010. Net reserves of the Trust's Royalty are calculated at the aggregate level from the net revenue of each of the Working Interest Owners. To estimate net gas reserves, the total net revenue is divided by the net value of 1 Mcf of gas. The net value of 1 Mcf of gas is the gas price per Mcf, plus the condensate value per Mcf of gas, plus the NGL value per Mcf of gas. The net condensate and NGL reserves are calculated by multiplying their respective yields by the net gas reserves. Revenue values used in the Reserve Report were estimated using the following prices: (1) condensate prices $48.80 per bbl; (2) NGL prices $25.63 per bbl for San Juan Properties, $31.96 per bbl for Hugoton Properties; and (3) natural gas prices $2.24 per Mcf for San Juan Properties, $2.95 per Mcf for Hugoton Properties, with the initial prices also used as weighted average prices held constant thereafter over the lives of the properties. Estimates of operating expenses were based on current expenses and used for the life of the properties with no increases in the future based on inflation.

Preparation of Reserve Estimates

For further information regarding the Net Overriding Royalty Interest, the Basis of Accounting and Supplemental Reserve Information, see Notes 2, 3 and 10, respectively, in the Notes to Financial Statements contained in Item 8 of this Form 10-K.

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. Reserve data included above and in these reports represent estimates only and should not be construed as being exact. The discounted present values shown by 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.

The Trustee has been advised that each of the foregoing estimates were prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board. Accordingly, the estimates are based on existing economic and operating conditions in effect at December 31, 2009, with no provision for future increases or decreases except for periodic price redeterminations in accordance with existing gas contracts. Actual future prices and costs may be materially greater or less than the assumed amounts in the reserve reports. Because the reserve reports are limited to proved reserves, future capital expenditures for recovery of reserves not classified as proved are not included in the calculation of estimated future net revenues. 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 DeGolyer and MacNaughton.

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Accordingly, reserve estimates are often different from the quantities of hydrocarbons that are ultimately recovered.

The Trustee relies on DeGolyer and MacNaughton to prepare the reserve estimated attributable to the Trust's interests in the Royalty Properties. Although the Trustee inquires with the third-party reserve engineer about the information provided by the working interest owners and the assumptions made and methodologies used by the third-party reserve engineer, the Trustee does not control the information provided by the working interest owners or the assumptions made or methodologies used by the third-party reserve engineer. Accordingly, such information is outside the scope of the internal controls of the Trust and the Trustee.

As noted above in this report, the Trustee is currently investigating certain payments and differences from original estimates. The Trustee is also reviewing, with the assistance of outside experts, prior allocations of payments of Royalty income by the working interest owners. Any past practices not consistent with the Conveyance could also cause the basis for the reserve estimates included above to differ from actual reserve quantities and future net revenues.

Income, Production and Production Prices and Production Costs

Reference is made to "Management's Discussion and Analysis of Financial Condition and Results of Operations Summary of Royalty Income, Production, Prices and Costs" under Item 7 of this Form 10-K for information concerning income, production, production prices and costs 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 44% of the Royalty income of the Trust during 2009.

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 2009, the primary purchaser was 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 lower for the year ended December 31, 2009 as compared to the year ended December 31, 2008.

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. The contract is extended a year in advance, so PNR extended the contract to June 1, 2011. 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 by WRI to Kansas Gas Service ("Oneok").

Beginning July 1, 2007, the Hugoton and Panoma fields are considered a single, common source of supply and operate under a single combined Basic Proration Order (BPO). After July 1, 2007, the wells in each of these fields are allowed to produce at their open flow potential and will no longer be subject to allowable restrictions and any and all average or underage that a well may have accrued will be cancelled.

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 56% of the Royalty income of the Trust during 2009. 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 decreased from $6.42 per Mcf in 2006 to $6.37 per Mcf in 2007, increased to $8.07 per Mcf in 2008 and then decreased to $3.72 per Mcf in 2009 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.

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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 two decades, the FERC adopted regulations resulting in a restructuring of the natural gas industry. The principal 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 and other 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. Recent changes to, or interpretations of, environmental laws, particularly the federal Clean Air Act and particularly with regard to regulation of greenhouse gases such as natural gas, may place additional obligations on emissions of natural gas associated with oil field operations. Increased sensitivity to and regulation of greenhouse gas emissions may also place additional restrictions or requirements for environmental studies on oil and gas leases and lease extensions. 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, a 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.

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Moreover, government regulations, such as regulation of natural gas transportation, regulation of greenhouse gas and other emissions associated with fossil fuel combustion, 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.

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.

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Physical effects of climatic change have the potential to damage the facilities of the working interest owners, disrupt production activities on the Royalty Properties, and cause the working interest owners to incur significant costs in preparing for or responding to those effects and can adversely affect Trust distributions as a result.

Scientific studies and government reports, such as those published by the Intergovernmental Panel on Climate Change established by the United Nations and World Meteorological Organization indicate that climate change could have global, regional or local effects on the severity of weather (including hurricanes, floods and droughts), sea levels, arability of farmland, and water availability and quality, including predicted effects on areas in which the Royalty Properties are located. If such effects were to occur, exploration and production operations of the Royalty Properties have the potential to be adversely affected. Potential adverse effects could include damages to the facilities of the working interest owners or disruption of production activities associated with weather related events, scale-backs in operations on the Royalty Properties due to the threat of such climatic effects, and increases in costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climatic effects or increased costs for insurance coverages. Working interest owners may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change and can adversely affect Trust distributions as a result.

The Trustee relies entirely on reserve estimates and related information prepared by DeGoyler and McNaughton based on information provided by the working interest owners. 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, or damage to the environment or natural resources, and associated 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.

Further, the present value of future net cash flows from proved reserves may not be the current market value of estimated natural gas and oil reserves attributable to the Royalty. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on the 12-month average oil and gas index prices, calculated as the un-weighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the

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10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board (FASB) in Accounting Standards Codification 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

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 and 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. This reliance includes the use of an independent petroleum engineering

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consultant to prepare estimates of net proved reserves attributable to the Trust. This independent petroleum engineering consultant in turn relies on information provided to it by the working interest owners. 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.

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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.

None.

Item 2. Properties.

The Trust owns property interests in the Hugoton Area (Kansas) and the San Juan Basin (Northwestern New Mexico and Southwestern Colorado). See "Business Description of Royalty Properties" contained in 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. The Trustee has been advised by PNR, ConocoPhillips and BP Amoco that it is subject to litigation in the ordinary course of business for certain matters that include the Royalty Properties. While each of the working interest owners 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. [Reserved].

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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 under the ticker symbol "MTR". The high and low sales prices and distributions per unit for each quarter in the two years ended December 31, 2009 and December 31, 2008, were as follows:

	2009			2008		
Quarter	High	Low	Distribution	High	Low	Distribution
First	$ 47.00	$ 15.00	$ .5827	$ 72.00	$ 53.98	$ 1.5411
Second	$ 31.40	$ 25.04	$ .3763	$ 84.28	$ 67.01	$ 1.8537
Third	$ 35.90	$ 22.62	$ .4629	$ 86.86	$ 60.00	$ 2.4201
Fourth	$ 43.85	$ 32.14	$ .6410	$ 64.50	$ 35.55	$ 1.5720

At February 28, 2010, the 1,863,590 units outstanding were held by 868 unitholders of record.

Item 6. Selected Financial Data.

	2009	2008	2007	2006	2005
Royalty income	$ 4,052,357	$ 13,845,456	$ 12,216,271	$ 9,809,030	$ 10,568,610
Distributable income	$ 3,844,464	$ 13,768,502	$ 12,222,045	$ 9,771,034	$ 10,522,777
Distributable income per unit	$ 2.0629	$ 7.3882	$ 6.5583	$ 5.2431	$ 5.6465
Total assets at year end	$ 7,580,604	$ 9,966,534	$ 11,503,570	$ 9,834,998	$ 11,905,561

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.

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;

(c) Trust general and administrative expenses, net of reimbursements, are recorded in the month they are included in the calculation of the monthly distribution amount;

(d) 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; and

(e) Distributions payable are determined on a monthly basis and are payable to unitholders of record as of the last business day of each month or such later date as the Trustee determines is required to comply with applicable law or stock exchange requirements.

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, general and administrative expenses would be recorded in the month they accrue, 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 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.

During 2008, the Trustee engaged an independent consulting firm to audit revenues, expenses and established reserves of certain working interest owners. This review and audit remains ongoing. While this audit has highlighted issues that remain open, the Trustee has not determined at this time whether any audit exceptions will result in any material gains or expenses net to the Trust.

Financial Review

Years 2009 and 2008

	Years Ended December 31,	
	2009	**2008**
Royalty income	$ 4,052,357	$ 13,845,456
Interest income	335	50,869
General and administrative expenses	(208,228)	(127,823)
Distributable income	$ 3,844,464	$ 13,768,502
Distributable income per unit	$ 2.0629	$ 7.3882

The Trust's Royalty income was $4,052,357 in 2009, a decrease of approximately 71% as compared to $13,845,456 in 2008, primarily as a result of lower prices for natural gas and natural gas liquids.

Hugoton Field

Royalty income attributable to the Hugoton Royalty Properties was $1,784,437 in 2009, a decrease of approximately 70%, as compared to $5,988,724 in 2008, primarily due to decreases in prices for natural gas and natural gas liquids.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $3.58 per Mcf and $32.39 per barrel, respectively, in 2009 as compared to $8.07 per Mcf and $64.94 per barrel, respectively, in 2008. Net production attributable to the Hugoton Royalty was 327,657 Mcf of natural gas and 18,836 barrels of natural gas liquids in 2009 as compared with 516,468 Mcf of natural gas and 28,039 barrels of natural gas liquids in 2008. Actual production volumes attributable to the Hugoton properties were 629,914 Mcf of natural gas and 35,765 barrels of natural gas liquids in 2009 as compared with 656,737 Mcf of natural gas and 35,501 barrels of natural gas liquids in 2008. The decrease in natural gas production for the year ended December 31, 2009 compared to the same period in 2008 is the result of natural production decline.

The Hugoton capital expenditures were $204,149 for 2009, an increase of approximately 1258% as compared to $15,032 for 2008. The increase in the capital expenditures was primarily due to the drilling of two additional wells. Operating costs were $1,427,521 during 2009, a decrease of approximately 8%

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as compared to $1,557,932 during 2008 due to cost control measures implemented due to market conditions.

San Juan Basin

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 $2,216,807 in 2009 as compared to $7,064,784 in 2008, a decrease of 69%. The decrease in Royalty income was due primarily to decreased natural gas and natural gas liquids prices in 2009. Net production attributable to the San Juan Basin Royalty located in the state of New Mexico was 467,692 Mcf of natural gas and 37,610 barrels of natural gas liquids, oil and condensate in 2009 as compared to 617,735 Mcf of natural gas and 50,308 barrels of natural gas liquids, oil and condensate in 2008. Actual production attributable to the San Juan Basin properties located in the state of New Mexico was 876,070 Mcf of natural gas and 69,478 barrels of natural gas liquids, oil and condensate in 2009 as compared with 849,707 Mcf of natural gas and 67,025 barrels of natural gas liquids, oil and condensate in 2008. The increase in gas and natural gas liquids production volumes for the year ended December 31, 2009 compared to the same period 2008 was due to production interruptions due to gas plant fires, inclement weather and repair and workover activity in 2008. 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 $2.63 per Mcf and $26.25 per barrel, respectively, in 2009 compared with $6.74 per Mcf and $57.67 per barrel, respectively, in 2008.

San Juan New Mexico capital expenditures were $750,879 during 2009, a decrease of approximately 9% as compared to $827,206 during 2008. The decrease in capital expenditures was due to a decrease in drilling activity. Operating costs were $1,160,198 during 2009, a decrease of approximately 33% as compared to $1,733,498 during 2008. The decrease in operating costs during 2009 compared to 2008 is the result of decreased repair and maintenance activity.

Royalty income from the San Juan Basin Colorado Royalty Properties was $51,113 in 2009 as compared to $791,948 in 2008. The decrease in royalty income was primarily the result of lower natural gas prices and an increase in excess production costs. Net production attributable to the San Juan Basin Royalty properties primarily located in Colorado was 22,191 Mcf of natural gas in 2009 as compared to 133,101 Mcf of natural gas in 2008. The average price received for natural gas from these San Juan Basin properties was $2.30 per Mcf in 2009 as compared with $5.95 per Mcf in 2008. Actual natural gas production volumes attributable to the San Juan Basin Colorado Properties were 157,224 Mcf in 2009 as compared with 156,917 Mcf in 2008. There was no actual or net production of natural gas liquids or oil and condensate from the San Juan Basin, Colorado Properties during 2009 and 2008.

Years 2008 and 2007

	Years Ended December 31,	
	2008	**2007**
Royalty income	$ 13,845,456	$ 12,216,271
Interest income	50,869	97,278
General and administrative expenses	(127,823)	(91,504)
Distributable income	$ 13,768,502	$ 12,222,045
Distributable income per unit	$ 7.3882	$ 6.5583

The Trust's Royalty income was $13,845,456 in 2008, an increase of approximately 13% as compared to $12,216,271 in 2007, primarily as a result of increased prices for natural gas and natural gas liquids.

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Hugoton Field

Royalty income attributable to the Hugoton Royalty Properties was $5,988,724 in 2008, an increase of approximately 5%, as compared to $5,705,773 in 2007, primarily as a result of higher prices for natural gas and natural gas liquids, offset in part by lower production volumes and by payments and interest received during 2007 of approximately $1,100,000 to partially settle claims made in the *John Steven Alford and Robert Larrabee v. Pioneer* lawsuit discussed in Note 6 to the Notes to Financial Statements under Item 8 of this Form 10-K.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $8.07 per Mcf and $64.94 per barrel, respectively, in 2008 as compared to $6.07 per Mcf and $42.85 per barrel, respectively, in 2007. Net production attributable to the Hugoton Royalty was 516,468 Mcf of natural gas and 28,039 barrels of natural gas liquids in 2008 as compared with 543,241 Mcf of natural gas and 30,625 barrels of natural gas liquids in 2007. Actual production volumes attributable to the Hugoton properties were 656,737 Mcf of natural gas and 35,501 barrels of natural gas liquids in 2008 as compared with 759,786 Mcf of natural gas and 36,660 barrels of natural gas liquids in 2007. The decrease in gas and natural gas liquids production for the year ended December 31, 2008 compared to the same period in 2007 was primarily due to natural decline and the nitrogen rejection unit being down for a portion of January and February in 2007. The shutdown of the nitrogen rejection unit increases the gas production while it decreases the natural gas liquids production.

The Hugoton capital expenditures were $15,032 for 2008, a decrease of approximately 90% as compared to $144,555 for 2007. The decrease in the capital expenditures was primarily due to fewer capital workovers in 2008. Operating costs were $1,557,932 during 2008, an increase of approximately 10% as compared to $1,422,450 during 2007 due to increases in production taxes, well workers, and higher rates charged by service providers.

San Juan Basin

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 $7,064,784 in 2008 as compared to $5,316,376 in 2007, an increase of 33%. The increase in Royalty income was due primarily to higher prices for natural gas and natural gas liquids and decreased capital expenditures during 2008. Net production attributable to the San Juan Basin Royalty located in the state of New Mexico was 617,735 Mcf of natural gas and 50,308 barrels of natural gas liquids, oil and condensate in 2008 as compared to 578,316 Mcf of natural gas and 56,188 barrels of natural gas liquids, oil and condensate in 2007. Actual production attributable to the San Juan Basin properties located in the state of New Mexico was 849,707 Mcf of natural gas and 67,025 barrels of natural gas liquids, oil and condensate in 2008 as compared with 941,366 Mcf of natural gas and 73,888 barrels of natural gas liquids, oil and condensate in 2007. The decrease in gas and natural gas liquids production volumes for the year ended December 31, 2008 compared to the same period 2007 was due to production interruptions due to gas plant fires, inclement weather and repair and workover activity in 2008. 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 $6.74 per Mcf and $57.67 per barrel, respectively, in 2008 compared with $5.36 per Mcf and $39.45 per barrel, respectively, in 2007.

San Juan New Mexico capital expenditures were $827,206 during 2008, a decrease of approximately 18% as compared to $1,007,366 during 2007. The decrease in capital expenditures was due to a decrease in development drilling. Operating costs were $1,733,498 during 2008, an increase of approximately 6% as compared to $1,638,835 during 2007. The increase in operating costs during 2008 compared to 2007 was due to increased workover, repair and maintenance activity.

The costs related to the San Juan Basin, Colorado portion of the Fruitland Coal drilling program were recovered in December 2004. However, subsequent earnings were not remitted to the Trust until

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December 2006 and July 2007. 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 2006, BP remitted $978,349 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings related to the properties it operates. In July 2007, Red Willow remitted $159,497 for payment of undistributed earnings from January 2005 through December 2006 for the San Juan Basin Colorado Royalty properties it operates. BP communicated to the Trust these distributions represent all of the previously unpaid revenues. The Trustee does not expect to receive the $142,566 difference in the original estimate of unpaid proceeds of $1,280,412 and the payment of $1,137,846. Since Royalty income for the Trust is recorded on a cash basis, the earnings for the year ended December 31, 2006 were not recognized as income until the quarter ended December 31, 2006 and September 30, 2007.

Royalty income from the San Juan Basin Colorado Royalty Properties was $791,948 in 2008 as compared to $1,194,122 in 2007. Net production attributable to the San Juan Basin Royalty properties primarily located in Colorado was 133,101 Mcf of natural gas in 2008 as compared to 194,775 Mcf of natural gas in 2007. The average price received for natural gas from these San Juan Basin properties was $5.95 per Mcf in 2008 as compared with $5.99 per Mcf in 2007. Actual natural gas production volumes attributable to the San Juan Basin Colorado Properties were 156,917 Mcf in 2008. There was no actual or net production of natural gas liquids or oil and condensate from the San Juan Basin, Colorado Properties during 2008. During 2007, net production of natural gas liquids, oil and condensate from the San Juan Basin, Colorado Properties was 734 barrels and actual production was 1,348 barrels. Operating costs for the San Juan Basin properties were $161,286 in 2008 as compared to $136,772 in 2007.

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

			San Juan					
	Hugoton		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, 2009:								
The Trust's proportionate share of								
Gross Proceeds(1)	$ 2,257,598	$ 1,158,509	$ 2,304,527	$ 1,823,357	$ 390,056	$	$ 4,952,181	$ 2,981,866
Less the Trust's proportionate share of								
Capital costs	(136,794)	(67,355)	(423,566)	(327,313)			(560,360)	(394,668)
Operating costs	(946,519)	(481,002)	$ (651,272)	(508,926)	(359,549)		$ (1,957,340)	(989,928)
Net Proceeds(2)	$ 1,174,285	$ 610,152	$ 1,229,689	$ 987,118	$ 30,507	$	$ 2,434,481	$ 1,597,270
Royalty Income(2)	1,174,285	610,152	1,229,689	987,118	51,113	0	2,455,087	1,597,270
Average Sales Price	$ 3.58	$ 32.39	$ 2.63	$ 26.25	$ 2.30	$	$ 3.00	$ 28.29
Average Production Costs(3)	$ 3.31	$ 29.11	$ 2.30	$ 22.23	$ 16.20	$ 0	$ 3.80	$ 24.53
Net production volumes attributable to the	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Royalty paid(4)	327,657	18,836	467,692	37,610	22,191		817,540	56,446
Year ended December 31, 2008:								
The Trust's proportionate share of								
Gross Proceeds(1)	$ 5,257,637	$ 2,304,051	$ 5,740,154	$ 3,885,334	$ 953,234	$	$ 11,951,025	$ 6,189,385
Less the Trust's proportionate share of								
Capital costs	(9,181)	(5,851)	(515,425)	(311,781)			(524,606)	(317,632)
Operating costs	(1,080,559)	(477,373)	$ (1,061,194)	(672,304)	(161,286)		$ (2,303,039)	(1,149,677)
Royalty Income	$ 4,167,897	$ 1,820,827	$ 4,163,535	$ 2,901,249	$ 791,948	$	$ 9,123,380	$ 4,722,076

Average Sales Price	$ 8.07	$ 64.94	$ 6.74	$ 57.67	$ 5.95	$	$ 7.20	$ 60.27
Average Production Costs(3)	$ 2.11	$ 17.23	$ 2.55	$ 19.56	$ 1.21	$ 0	$ 2.23	$ 18.73
Net production volumes attributable to the	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Royalty paid(4)	516,468	28,039	617,735	50,308	133,101		1,267,304	78,347
Year ended December 31, 2007:								
The Trust's proportionate share of								
Gross Proceeds(1)	$ 5,702,879	$ 1,569,899	$ 5,047,932	$ 2,914,645	$ 1,309,166	$ 28,771	$ 12,059,977	$ 4,513,315
Less the Trust's proportionate share of								
Capital costs	(107,490)	(37,065)	(714,876)	(292,490)	(6,939)	(104)	(829,305)	(329,659)
Operating costs	(1,201,906)	(220,544)	(1,233,284)	(405,551)	(135,524)	(1,248)	(2,570,714)	(627,343)
Royalty Income	$ 4,393,483	$ 1,312,290	$ 3,099,772	$ 2,216,604	$ 1,166,703	$ 27,419	$ 8,659,958	$ 3,556,313
Average Sales Price	$ 6.07	$ 42.85	$ 5.36	$ 39.45	$ 5.99	$ 37.36	$ 6.62	$ 40.62
Average Production Costs(3)	$ 2.41	$ 8.41	$ 3.37	$ 12.42	$ .73	$ 1.84	$ 2.58	$ 10.93
Net production volumes attributable to the	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Royalty paid(4)	543,241	30,625	578,316	56,188	194,775	734	1,316,332	87,547

(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.

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(2)
As a result of excess production costs incurred in one monthly operating period and then recovered in a subsequent monthly operating period(s), the Royalty income paid to the Trust may not agree to the Trust's royalty interest in the Net Proceeds. Excess production costs related to the San Juan Basin Colorado properties operated by BP were approximately $20,606 as of December 31, 2009. The excess production costs must be recovered by the Working Interest Owners before any distribution of Royalty income will be made to the Trust.

(3)
Average production costs attributable to the Royalty are calculated as stated capital costs plus operating costs, divided by stated net production volumes attributable to the Royalty paid. As noted above in footnote (2), production costs may be incurred in one operating period and then recovered in a subsequent operating period, which may cause Royalty income paid to the Trust not to agree to the Trust's Royalty interest in the Net Proceeds.

(4)
Net production volumes attributable to the Royalty are determined by dividing Royalty income by the average sales price received. Net production volumes attributable for Hugoton Royalty for 2007 were not calculated for the 2007 reimbursement from PNR related to the *Alford* settlement.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

None.

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

The Trust does not engage in any operations, and does not utilize market risk sensitive instruments, either for trading purposes or for other than trading purposes. The Trust's monthly distributions are highly dependent upon the prices realized from the sale of natural gas. Natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and the working interest owners. Factors that contribute to price fluctuation include, among others:

- political conditions worldwide, in particular political disruption, war or other armed conflict in or affecting oil producing regions;
- worldwide economic conditions;
- weather conditions, including hurricanes and tropical storms in the Gulf of Mexico;
- 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, regulation of greenhouse gas and other emissions associated with fossil fuel combustion, and price controls, can affect product prices in the long term.

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Item 8. Financial Statements and Supplementary Data.

MESA ROYALTY TRUST
STATEMENTS OF DISTRIBUTABLE INCOME

	Years Ended December 31,		
	2009	2008	2007
Royalty income	$ 4,052,357	$ 13,845,456	$ 12,216,271
Interest income	335	50,869	97,278
General and administrative expenses	(208,228)	(127,823)	(91,504)
Distributable income	$ 3,844,464	$ 13,768,502	$ 12,222,045
Distributable income per unit	$ 2.0629	$ 7.3882	$ 6.5583

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31,	
	2009	2008
ASSETS		
Cash and short-term investments	$ 1,194,604	$ 2,917,460
Interest receivable		14,035
Net overriding royalty interests in oil and gas properties	42,498,034	42,498,034
Less: accumulated amortization	(36,112,034)	(35,462,995)
Total assets	$ 7,580,604	$ 9,966,534
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 1,194,604	$ 2,931,495
Trust corpus (1,863,590 units of beneficial interest authorized and outstanding)	6,386,000	7,035,039
Total liabilities and trust corpus	$ 7,580,604	$ 9,966,534

STATEMENTS OF CHANGES IN TRUST CORPUS

	Years Ended December 31,		
	2009	2008	2007
Trust corpus, beginning of year	$ 7,035,039	$ 7,692,213	$ 8,102,715
Distributable income	3,844,464	13,768,502	12,222,045
Distributions to unitholders	(3,844,464)	(13,768,502)	(12,222,045)
Amortization of net overriding royalty interests	(649,039)	(657,174)	(410,502)
Trust corpus, end of year	$ 6,386,000	$ 7,035,039	$ 7,692,213

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

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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 an overriding royalty interest (the "Royalty") equal to 90% of the Net Proceeds (as defined in the Conveyance and described below) attributable to the specified interests in properties conveyed by the assignor on that date (the "Subject Interests"). The Subject Interests consisted of interests 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"). The Royalty is evidenced by counterparts of an Overriding Royalty Conveyance dated as of November 1, 1979 (the "Conveyance"). 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. Effective January 1, 2005, ConocoPhillips assigned its interest in an immaterial number of San Juan Basin Royalty Properties located in New Mexico to XTO Energy Inc. 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 Mellon 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

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(1) Trust Organization and Provisions (Continued)

(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.

(2) Net Overriding Royalty Interest

In accordance with the Conveyance, the Working Interest Owners are obligated to calculate and pay the Trust each month the Royalty which is equal to 90% of the Net Proceeds (as defined in the Conveyance) attributable to the month. In 1985, the Trust Indenture was amended and the Trust conveyed to an affiliate of Mesa Petroleum Co. 88.5571% of the original Royalty (such transfer, the "1985 Assignment"). The effect of the assignment was an overall reduction of approximately 88.56% in the size of the Trust. As a result, the Trust is now entitled to receive 11.44% of 90% of the Net Proceeds attributable to each month.

The Net Overriding Royalty Interest is reviewed for impairment whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. If circumstances require the Net Overriding Royalty Interest to be tested for possible impairment, the Trust first compares undiscounted cash flows expected to be generated by the Net Overriding Royalty Interest to its carrying value. If the carrying value of the Net Overriding Royalty Interest is not recoverable on an undiscounted cash flow basis, an impairment is recognized to the extent that the carrying value exceeds its fair value. The fair value of the Net Overriding Royalty Interest is measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount.

(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;

(c) Trust general and administrative expenses, net of reimbursements, are recorded in the month they are included in the calculation of the monthly distribution amount;

(d) 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; and

(e) Distributions payable are determined on a monthly basis and are payable to unitholders of record as of the last business day of each month or such later date as the Trustee determines is required to comply with applicable law or stock exchange requirements.

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

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(3) Basis of Accounting (Continued)

calculated or received, general and administrative expenses would be recorded in the month they accrue, and interest income for a month would be calculated only through the end of such month.

The preparation of the financial statements requires estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates. The Trust considers all highly liquid investments with a maturity of three months or less to be cash equivalents. Subsequent events were evaluated through the issuance date of the financial statements.

(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 incurs no federal income tax liability and each unitholder is subject to tax on the unitholder's pro rata share of the income and expense of the Trust as if the unitholder were the direct owner of a pro rata share of the Trust's assets.

The Trustee assumes that some Trust Units are held by a middleman, as such term is broadly defined in U.S. Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. Bank of New York Mellon Trust Company, N.A., 919 Congress Avenue, Austin, Texas 78701, telephone number 1-800-852-1422, is the representative of the Trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT.

(6) PNR Legal Proceedings

There are no pending legal proceedings to which the Trust is a named party. The Trustee has been advised by PNR, ConocoPhillips and BP Amoco that it is subject to litigation in the ordinary course of business for certain matters that include the Royalty Properties. While each of the working interest owners 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.

PNR has advised the Trustee that the previously reached 2006 settlement in the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.,* filed in the 26th Judicial District Court, Stevens County, Kansas, was approved in the first quarter of 2007 by the Judge and the case was finalized in April 2007. The plaintiffs in the

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(6) PNR Legal Proceedings (Continued)

above noted lawsuit were royalty owners in oil and gas properties located in the Hugoton field, which are owned by Pioneer USA, a subsidiary of 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 agreed to 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 approximately $32,700,000. Pioneer agreed to pay the cash portion in two installments. Pioneer 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 $986,138 payable on September 30, 2007. The $986,138 attributable to the Trust paid on September 30, 2006, was deducted from royalty income in the fourth quarter of 2006. In October 2007, Pioneer informed the Trustee that during the course of Pioneer USA's analysis of the payments under the terms of the settlement agreement, Pioneer USA determined that the Trust should not bear any portion of the second installment payment and that Pioneer USA should reimburse the Trust for the portion of the first installment payment previously charged to the Trust and paid in September 2006. As a result, Pioneer USA included a reimbursement of $1,096,630, including interest in the amount of $110,492, to the distribution made to the Trust in October 2007 were included in the Trust's fourth quarter receipts in 2007, and no portion of the second installment payment was charged to the Trust.

(7) Excess Production Costs

The Trust did not receive any Royalty income associated with the San Juan Basin Colorado royalty properties operated by BP during 2009 due to excess production costs incurred during such period. Excess production costs result when costs, charges, and expenses attributable to a Working Interest Property exceed the revenue received from the sale of oil, gas, and other hydrocarbons produced from such property. Excess production costs related to the San Juan Basin Colorado properties were approximately $20,606 as of December 31,2009. The excess production costs must be recovered by the Working Interest Owners before any distribution of Royalty income from the properties will be made to the Trust.

(8) Tax Assessment

PNR has advised the Trustee that it received a proposed assessment from the Kansas Department of Revenue on September 10, 2009, for additional tax, penalty and interest of approximately $4.1 million resulting primarily from the settlement of the lawsuit John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc. in early 2007. The portion of the tax assessment net to the Trust is approximately $181,000, which could adversely affect Trust distributions. PNR has submitted a written response objecting to the proposed assessment. No assurance can be made that any objections or disputed items raised by PNR will be successful.

PNR has also advised the Trustee that it is preparing to file for a severance tax refund with the state of Kansas for approximately $2.8 million, the estimated share of the refund due the Trust is approximately $156,000. There can be no assurance that the state will agree to PNR's position.

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(9) Recently Issued Pronouncements

In June 2009, the FASB established the FASB Accounting Standards Codification (Codification), which officially commenced July 1, 2009, to become the source of authoritative US GAAP recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative US GAAP for SEC registrants. Generally, the Codification is not expected to change US GAAP. All other accounting literature excluded from the Codification will be considered nonauthoritative. The Codification is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We adopted the new standards for our quarter ending September 30, 2009. All references to authoritative accounting literature are now referenced in accordance with the Codification.

In May 2009, the FASB issued FASB ASC 855, *"Subsequent Events,"* and in February 2010, the FASB issued ASC Update 2010-09, *"Subsequent Events (Topic 855) Amendments to Certain Recognition and Disclosure Requirements,"* which establishes standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. Under this standard, entities that file or furnish financial statements with the SEC, such as the Trust, are required to use an issued date in evaluating subsequent events. This standard, as updated, is effective February 24, 2010, and the Trust adopted it at that date. The adoption did not have a material impact on the Trust's results of operations or financial position.

(10) Supplemental Reserve Information (Unaudited)

Effective for fiscal years ending on or after December 2009, the SEC approved revisions designed to modernize the oil and gas company reserve reporting requirements. The most significant amendments to the requirements include the following:

- commodity prices economic producibility of reserves and discounted cash flows will be based on a 12-month average commodity price unless contractual arrangements designate the price to be used;

- disclosure of unproved reserves probable and possible reserves may be disclosed separately on a voluntary basis;

- proved undeveloped reserve guidelines reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered;

- reserve estimation using new technologies reserves may be estimated through the use of reliable technology in addition to flow tests and production history; and

- nontraditional resources the definition of oil and gas producing activities will expand and focus on the marketable product rather than the method of extraction.

The trust adopted the new requirements effective December 31, 2009. The adoption did not have a material impact on the trust's distributable income or financial position. The impact of the adoption due to the estimation of reserves using the average price instead of the year end price at December 31, 2009 was a decrease of approximately 1,363 MMcfe of proved reserves or $9.8 million of undiscounted future royalty income. There were no other significant impacts of adoption.

Estimates of the proved oil and gas reserves attributable to the Hugoton and San Juan Basin Royalty Properties as of December 31, 2009 and 2008 are based on reports prepared by DeGolyer and MacNaughton, independent petroleum engineering consultants. Estimates of the proved oil and gas

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(10) Supplemental Reserve Information (Unaudited) (Continued)

reserves attributable to the Hugoton Royalty Properties as of December 31, 2007 and 2006 are based on reports prepared by Pioneer. Estimates of the proved oil and gas reserves attributable to the San Juan Basin Royalty Properties as of December 31, 2007 and 2006 are based on reports prepared by DeGoyler and MacNaughton and ConocoPhillips, respectively. 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's Royalty were estimated by allocating to the Trust a portion of the estimated combined net reserve volumes of the Hugoton Royalty Properties and San Juan Basin Royalty Properties based on future net revenue. Production volumes are allocated based solely on royalty income. Because the net reserve volumes attributable to the Trust's Royalty 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's Royalty 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.

In accordance with revised SEC regulations, reserves for natural gas and oil, condensate and natural gas liquids at December 31, 2009, were based on the average price during the 12 month period, determined as an unweighted average of the first-of-the-month price for each month, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. In accordance with SEC regulations, reserves for all prior years were estimated using year-end prices. 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

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(10) Supplemental Reserve Information (Unaudited) (Continued)

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.

ESTIMATED QUANTITIES OF PROVED AND PROVED DEVELOPED RESERVES
(Unaudited)

	Oil, Condensate and Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Reserves:		
December 31, 2006	2,539,396	33,563,951
Revisions to previous estimates	(1,538,328)	(14,856,500)
Extensions, discoveries and other additions		
Production	(91,356)	(1,285,368)
December 31, 2007	909,712	17,422,083
Revisions to previous estimates	(221,394)	(6,622,313)
Extensions, discoveries and other additions		
Production	(78,347)	(1,267,304)
December 31, 2008	609,971	9,532,466
Revisions to previous estimates	(79,839)	(2,028,356)
Extensions, discoveries and other additions	11,264	193,083
Production	(56,446)	(817,540)
December 31, 2009	484,950	6,879,653
Proved Developed Reserves:		
December 31, 2006	2,531,396	32,229,951
December 31, 2007	909,712	17,422,083
December 31, 2008	609,971	9,532,466
December 31, 2009	478,913	6,773,482
Proved Undeveloped Reserves:		
December 31, 2006	2,000	1,334,000
December 31, 2007		
December 31, 2008		

December 31, 2009	6,037	106,171

The Hugoton Royalty represents 33%, 27%, and 47% of the estimated proved oil, condensate and natural gas liquids reserves and 40%, 40%, and 41% of the estimated proved natural gas reserves as of December 31 of 2009, 2008 and 2007, respectively.

The December 31, 2007 reserve estimates for the San Juan Basin properties were prepared by a third party reservoir engineering firm, whereas the December 31, 2006 reserve estimates were prepared by

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(10) Supplemental Reserve Information (Unaudited) (Continued)

the Working Interest Owner. Revisions to previous estimates in 2007 are primarily due to professional differences in judgment regarding estimates of San Juan Basin reserves.

The December 31, 2009 and 2008 reserve estimates for the Hugoton properties were prepared by a third party reservoir engineering firm, whereas the December 31, 2007 and 2006 reserve estimates for the Hugoton properties were prepared by the Working Interest Owner. Revisions in previous estimates in 2009 are primarily due to decreases in natural gas and natural gas liquid prices. Revisions to previous estimates in 2008 are primarily due to professional differences in judgment regarding estimates of Hugoton reserves in addition to a decline in commodity prices.

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

	December 31, 2009	December 31, 2008	December 31, 2007
	(In thousands)		
The Trust's proportionate share of future gross proceeds	$ 74,221	$ 112,402	$ 180,349
Less the Trust's proportionate share of Future operating costs	(41,762)	(51,677)	(26,053)
Future capital costs	(1,438)		(191)
Future royalty income	31,021	60,725	154,105
Discount at 10% per annum	(13,210)	(27,364)	(80,353)
Standardized measure of future royalty income from proved oil and gas reserves	$ 17,811	$ 33,361	$ 73,752

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

	December 31, 2009	December 31, 2008	December 31, 2007
	(In thousands)		
Standardized measure at beginning of year	$ 33,361	$ 73,752	$ 81,086
Revisions of previous estimates	(89)	(10,482)	(35,821)
Net changes in price and production costs	(14,807)	(23,439)	32,594
Extensions, discoveries and other additions	61		
Royalty income	(4,052)	(13,845)	(12,216)
Accretion of discount	3,337	7,375	8,109
Net changes in standardized measure	(15,550)	(40,391)	(7,334)

Standardized measure at end of year	$ 17,811	$ 33,361	$ 73,752

The Hugoton Royalty represents approximately 43% and 39% of the standardized measure of future royalty income for 2009 and 2008, respectively.

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MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(10) Supplemental Reserve Information (Unaudited) (Continued)

Standardized measure at December 31, 2009 was calculated using natural gas prices of $2.95 per Mcf for Hugoton properties and $2.24 for the San Juan properties.

Selected Quarterly Financial Data (Unaudited)

	Summarized Quarterly Results Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
2009:				
Royalty income	$ 1,134,774	$ 745,374	$ 923,220	$ 1,248,989
Distributable income	$ 1,085,935	$ 701,324	$ 862,601	$ 1,194,604
Distributable income per unit	$ .5827	$ .3763	$ .4629	$ .6410
2008:				
Royalty income	$ 2,884,508	$ 3,476,622	$ 4,535,119	$ 2,949,207
Distributable income	$ 2,872,024	$ 3,454,825	$ 4,510,158	$ 2,931,495
Distributable income per unit	$ 1.5411	$ 1.8539	$ 2.4201	$ 1.5730

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

**The Bank of New York Mellon 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, 2009 and 2008, 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, 2009. 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, 2009 and 2008, and the distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2009, 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), Mesa Royalty Trust's internal control over financial reporting as of December 31, 2009, 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 March 16, 2010 expressed an unqualified opinion on the effectiveness of the Trust's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
March 16, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited Mesa Royalty Trust's (the "Trust") internal control over financial reporting as of December 31, 2009, 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 Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included 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 Mesa Royalty Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the statements of assets, liabilities, and trust corpus of Mesa Royalty Trust as of December 31, 2009 and 2008, 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, 2009, and our report dated March 16, 2010 expressed an unqualified opinion on those financial statements.

/s/ KPMG LLP

Houston, Texas
March 16, 2010

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

None.

Item 9A. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and regulations. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated by the working interest owners to The Bank of New York Mellon Trust Company, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the trust officer acting on behalf of the Trustee responsible for the administration of the Trust conducted an evaluation of the Trustee's disclosure controls and procedures. The officer acting on behalf of the Trustee concluded that the Trust's disclosure controls and procedures were effective with respect to the Trustee and its employees.

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 Part I 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" for a description of certain risks relating to these arrangements and reliance, including filings such as this filing outside the time periods specified notwithstanding effective disclosure controls and procedures, of the Trustee regarding information under its control.

The officer acting on behalf of the Trustee has not conducted a separate evaluation of the disclosure controls and procedures with respect to information furnished by the working interest owners. The Trustee notes that with respect to the annual reports on Form 10-K for December 31, 2007 and 2008, and with respect to the quarterly reports during 2008 and for the first two quarters of 2009, the Trust did not file its reports in a timely manner due to the Trustee's need to reconcile and verify ownership, calculations of the Trust's interest in proceeds and other information provided by working interest owners. This information was required by the reserve engineer to prepare the reserve report for the Trustee to present the required reserve information in the SEC reports, and for the Trustee to complete the Trust's financial statements, and a review of the basis for this information was needed prior to filing these reports. The source of this information is not within the control of the Trustee, and thus the initial information provided to the Trustee and the timely receipt of accurate information for the preparation of these reports was not within scope of the Trustee's disclosure controls and procedures. The Trustee's review of certain information and calculations by the working interest owners, along with an outside joint venture auditor, remains ongoing. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources" under Item 7 of this Form 10-K for information concerning controls and procedures with respect to the Royalty.

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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, 2009. The Trustee's assessment of the effectiveness of the Trust's internal control over financial reporting as of December 31, 2009 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.

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 holders 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.

Title and Class of Voting Securities	Name and Address of Beneficial Ownership	Amount and Nature of Beneficial Ownership(1)	Percent of Class
Units of Beneficial Interest	Lucas Capital Management LLC 2 Bridge Ave. STE 632 Red Bank NJ 07701	104,879(2)	5.6%

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

(2) Based on information contained in the Rule 13d-1(b) filed on December 31, 2009 and Form SC 13G filed on January 14, 2010.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control. The Trustee is not aware of any arrangements, including the pledge of securities of the Trust, the operation of which may at a subsequent date result in a change in control of the Trust.

Item 13. Certain Relationships and Related Transactions, and 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.

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The following table presents fees for professional audit services rendered by KPMG LLP for the audit of the Mesa Royalty Trust financial statements for 2009 and 2008 and fees billed for other services rendered by KPMG LLP.

	2009	2008
Audit fees(1)	$ 440,000	$ 526,668
Audit-related fees		
Tax fees(2)	$ 45,000	40,000
All other fees		
Total fees	$ 485,000	$ 566,668

(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 2009 related to 2008 tax work and in 2008 for 2007 tax work. The Mesa Royalty Trust is reimbursed by the working interest owners for 88.56% of general and administrative expenses incurred.

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PART IV

Item 15. Exhibits and 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)	*Form of 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		
99.1	Summary Reserve Report from DeGolyer and MacNaughton		

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

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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 MELLON TRUST COMPANY, N.A., TRUSTEE

By: /s/ MIKE ULRICH

Mike Ulrich
Vice President & Trust Officer

March 16, 2010

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.

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EXHIBIT INDEX

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)	*Form of 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		
99.1	Summary Reserve Report from DeGolyer and MacNaughton		

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