MESA ROYALTY TRUST/TX
Form 10-K
March 29, 2013

Use these links to rapidly review the document
TABLE OF CONTENTS
PART IV

Table of Contents

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, 2012

Or

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

For the transition period from to
Commission file number: 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 (§ 229.405 of this chapter) 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 29, 2012 of $34.26 was approximately $63,846,593.

As of March 29, 2013, 1,863,590 Units of Beneficial Interest were outstanding in Mesa Royalty Trust.

DOCUMENTS INCORPORATED BY REFERENCE: None

Table of Contents

TABLE OF CONTENTS

		Page
	PART I	
Item 1.	Business	1
Item 1A.	Risk Factors	16
Item 1B.	Unresolved Staff Comments	23
Item 2.	Properties	23
Item 3.	Legal Proceedings	23
Item 4.	Mine Safety Disclosures	23
	PART II	
Item 5.	Market for the Registrant's Common Equity, Related Unitholder Matters and Issuer Purchases of Equity Securities	24
Item 6.	Selected Financial Data	24
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	24
	Summary of Royalty Income, Production, Prices and Costs (Unaudited)	29
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	30
Item 8.	Financial Statements and Supplementary Data	31
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	43
Item 9A.	Controls and Procedures	43
	PART III	
Item 10.	Directors, Executive Officers and Corporate Governance	44
Item 11.	Executive Compensation	45
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	45
Item 13.	Certain Relationships and Related Transactions, and Director Independence	45
Item 14.	Principal Accounting Fees and Services	45
	PART IV	
Item 15.	Exhibits and Financial Statement Schedules	46
SIGNATURES		48

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, who operate the oil and gas properties in which the Trust holds interests, 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. Risks factors that may affect actual results and Trust distributions include, without limitation:

The Trust's withholding of cash reserves for contingent liabilities and expenses in accordance with the Indenture;

Commodity price fluctuations;

Uncertainty of estimates of oil and gas production;

Table of Contents

Uncertainty of future production and development costs;

Operating risks for working interest owners, including drilling and environmental risks;

Regulatory changes;

Decisions by and at the discretion of working interest owners not to perform additional development projects or to abandon properties; and

Uncertainties inherent in estimating proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures.

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." Should any event or circumstances contemplated by the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should any material underlying assumptions prove incorrect, actual results may differ materially from future results expressed or implied by the forward-looking statements. 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.

Table of Contents

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;

Table of Contents

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 $3,781,422 and $6,661,178 for the years 2012 and 2011, 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

Table of Contents

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 29, 2013.

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.

Effective January 1, 2011, the Trustee began withholding $83,333 of cash per month for future unknown contingent liabilities and expenses in accordance with the Trust Indenture. The cash withholding was established through the withholding of cash received during 2011 of approximately $83,333 per monthly distribution amount, or up to $250,000 per quarter, until the cash withholding reached $1.0 million. At December 31, 2011, the Trust had withheld a total of $1.0 million which is included in cash and short term investments. The effect on distributable income per unit is as follows:

	Twelve Months Ended December 31,	
	2012	2011
Distributable Income Before Reserve for Contingent Liabilities and Expenses	$ 3,601,394	$ 6,507,541
Reserve for Contingent Liabilities and Expenses		(1,000,000)
Distributable Income Available for Distribution	$ 3,601,394	$ 5,507,541
Distributable Income Per Unit	$ 1.9325	$ 2.9554
Units Outstanding	1,863,590	1,863,590

Table of Contents

Liability of Unitholders

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

Federal Income Tax Matters

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

This summary is based on current provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed Treasury Regulations there under 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. Notwithstanding the foregoing, the middlemen holding units on behalf of unitholders, and not the Trustee of the Trust, are solely responsible for

Table of Contents

complying with the information reporting requirements under the Treasury Regulations with respect to such units, including the issuance of IRS Forms 1099 and certain written tax statements. 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% . Backup withholding will not normally apply to distributions to a unitholder, however, unless the unitholder fails to properly provide to the Trust his taxpayer identification number or the IRS notifies the Trust that the taxpayer identification number provided by the unitholder is incorrect.

Sale of Units

Generally, except for recapture items, the sale, exchange or other disposition of a unit will result in capital gain or loss measured by the difference between the tax basis in the unit and the amount realized. Effective for property placed in service after December 31, 1986, the amount of gain, if any, realized upon the disposition of oil and gas property is treated as ordinary income up to the amount of intangible drilling and development costs incurred with respect to the property and depletion claimed to the extent it reduced the taxpayer's basis in the property. Under this provision, depletion attributable to a unit acquired after 1986 will be subject to recapture as ordinary income upon disposition of the unit or upon disposition of the oil and gas property to which the depletion is attributable. The balance of any gain or any loss will be capital gain or loss if the unit was held by the unitholder as a capital asset, either long-term or short-term depending on the holding period of the unit. This capital gain or loss will be long-term if a unitholder's holding period exceeds one year at the time of sale or exchange. Under current law, the highest marginal U.S. federal income tax rate applicable to long-term capital gains of individuals is 20%. Moreover, this rate is subject to change by new legislation at any time. The deductibility of capital losses are subject to certain limitations. 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.

Additional Tax on Net Investment Income

A 3.8% Medicare tax on certain net investment income earned by individuals applies for taxable years beginning after December 31, 2012. For these purposes, investment income would generally include certain income derived from investments such as the units and gain realized by a unitholder from a sale of units. In the case of an individual, the tax will be imposed on the lesser of (i) the unitholder's net investment income or (ii) the amount by which the unitholder's modified adjusted gross income exceeds $250,000 (if the unitholder is married and filing jointly or a surviving spouse), $125,000 (if the unitholder is married and filing separately) or $200,000 (in any other case).

Table of Contents

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, a non-U.S. unitholder may be subject to United States federal income tax on the gain on the disposition of his units if he meets certain ownership thresholds.

In addition, if a foreign corporation elects under provisions of the Code to treat the income from the Royalty as effectively connected with the conduct of a United States trade or business, the corporation may also be subject to the U.S. branch profits tax at a rate of 30%. This tax is imposed on U.S. branch profits of a foreign corporation that are not reinvested in the U.S. trade or business. This tax is in addition to the tax on effectively connected income. The branch profits tax may be either reduced or eliminated by treaty. 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 advisor 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.

DESCRIPTION OF ROYALTY PROPERTIES

Producing Acreage and Wells as of December 31, 2012

	Producing Acres(1)		Producing Gas Wells(1)	
	Gross	Net	Gross	Net
Hugoton Area (Kansas)	99,654	99,413	469	408
San Juan Basin (Northwestern New Mexico and Southwestern Colorado)	40,716	31,328	3,005	335
Total	140,370	130,741	3,474	743

(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."

Table of Contents

Hugoton

The principal property interest conveyed to the Trust accounts for approximately 28% of the present value of the Trust's reserves and was carved out of PNR's working interest in 104,437 net producing acres in the Hugoton field. The life of the field is expected to extend beyond the year 2020.

The gas produced from the Hugoton properties is available for sale on the spot market. See "Contracts." Since the Hugoton field gas is sold in the intrastate and interstate markets, it is subject to state and federal laws and regulations. The Kansas Corporation Commission (the "KCC") is the state regulatory agency responsible for 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 72% of the present value 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 acres and 25,400 net acres with Fruitland Coal potential. The working interest owner has advised the Trust that, as of December 31, 2012, 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

Table of Contents

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 development wells drilled on the Royalty Properties during 2012. There were no exploratory wells drilled on the Royalty Properties during 2012, 2011 or 2010.

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, 2012. 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, 2012, of the Trust's ownership in the overriding royalty interest are presented below. Total liquid reserves (condensate plus natural gas

Table of Contents

liquids) are expressed in thousands of barrels (Mbbl) and gas reserves are expressed in thousands of cubic feet (Mcf).

	Net Reserves					
	BP	Conoco	Pioneer	Red Willow	XTO	Total
Proved Developed						
Oil and Natural Gas Liquids, Mbbl	0	258	19	0	1	278
Gas, Mcf	301	2,963	334	71	12	3,681
Proved Undeveloped						
Oil and Natural Gas Liquids, Mbbl	0	0	19	0	0	19
Gas, Mcf	0	0	333	0	0	333
Total, Proved						
Oil and Natural Gas Liquids, Mbbl	0	258	38	0	1	297
Gas, Mcf	301	2,963	667	71	12	4,014

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, 2012, 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	15,238	4,252	140	72	20,199

	BP	Conoco	Pioneer	Red Willow	XTO	Total
Standardized Measure of Future Net Royalty Income discounted at 10%(1)	345	8,691	2,534	87	49	11,706

(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 4, 2013. 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 $84.22 per bbl; (2) NGL prices $33.78 per bbl for San Juan Properties, $38.80 per bbl for Hugoton Properties; and (3) natural gas prices $2.04 per Mcf for San Juan Properties, $3.01 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 9, respectively, in the Notes to Financial Statements contained in Item 8 of this Form 10-K.

Table of Contents

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, 2012, 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. 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 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 38% of the Royalty income of the Trust during 2012.

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 2012, 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

Table of Contents

Royalty Properties were lower for the year ended December 31, 2012 as compared to the year ended December 31, 2011.

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, 2013. 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.

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 overage 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 54% of the Royalty income of the Trust during 2012. 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. Average annual wellhead prices decreased from $8.07 per Mcf in 2008 to $3.72 per Mcf in 2009, increased to $4.16 per Mcf in 2010, decreased to $3.95 per Mcf in 2011 and decreased to $2.66 per Mcf in 2012 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.

Table of Contents

REGULATION AND PRICES

General

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

FERC Regulation

In general, the FERC regulates the sale of natural gas in interstate commerce for resale and the transportation of natural gas in interstate commerce by interstate pipelines. 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. In addition to rulemaking proceedings, the FERC establishes new policies and regulations through policy statements and adjudications of individual pipeline matters. Further, additional changes to regulations may occur based on actions taken by the United States Congress and/or the courts. 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.

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act of 1978 and culminated in adoption of the Natural Gas Wellhead Decontrol Act that removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

Sales of crude oil, condensate, and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be just and reasonable and may be derived in a number of ways including, but not limited to, the FERC's indexing methodology.

As to these various types of regulation, 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

Table of Contents

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. These laws and regulations, including their state counterparts, can impose liability upon the owner, operator or lessee under a lease for the cost of cleanup of discharged materials or damages to natural resources resulting from oil and gas operations. These laws and regulations may, among other things:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

Violations of environmental laws, regulations, or permits can result in civil and criminal penalties as well as potential injunctions curtailing operations in affected areas. The working interest owners have advised the Trust that they are not at this time 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. The working interest owners have also advised the Trust that they maintain insurance for costs of cleanup obligations, but that they are not fully insured against all such risks.

The following is a summary of the existing laws, rules and regulations to which the operations of the properties comprising the underlying properties may be subject that are material to the operation of the Royalty Properties.

Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, referred to as "CERCLA" or the Superfund law, and comparable state laws impose liability,

Table of Contents

potentially without regard to fault or legality of the activity at the time, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of health studies. In addition, neighboring landowners and other third parties may file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

The properties comprising the Royalty Properties may have been used for oil and natural gas exploration and production for many years. Although the working interest owners believe that they have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, the properties comprising the Royalty Properties may have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under the working interest owners' control. These properties and the substances disposed or released on them may be subject to CERCLA, federal hazardous waste laws, and analogous state laws. Under such laws, the working interest owners could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial plugging or pit closure operations to prevent future contamination.

In addition, in the course of the working interest owner's operations, equipment may be exposed to naturally occurring radiation associated with oil and natural gas deposits, and this exposure may result in the generation of wastes containing naturally occurring radioactive materials, or "NORM." NORM wastes exhibiting trace levels of naturally occurring radiation in excess of established state standards are subject to special handling and disposal requirements, and any storage vessels, piping and work area affected by NORM may be subject to remediation or restoration requirements. Because some properties presently or previously comprising the Royalty Properties may have been used for oil and natural gas production operations for many years, it is possible that the working interest owners may incur costs or liabilities associated with elevated levels of NORM.

Waste Handling. The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as "RCRA," and comparable state statutes, regulate the management and disposal of solid and hazardous waste. Some wastes associated with the exploration and production of oil and natural gas are exempted from the most stringent regulation in certain circumstances, such as drilling fluids, produced waters and other wastes associated with the exploration, development or production of oil and natural gas. However, these wastes and other wastes may be otherwise regulated by the EPA or state agencies. Moreover, in the ordinary course of oil and gas operations, industrial wastes such as paint wastes and waste solvents may be regulated as hazardous waste under RCRA or considered hazardous substances under CERCLA. It is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into regulated waters. The Oil Pollution Act of 1990, or the OPA, as amended, which amends the Clean Water Act, imposes strict liability on owners and operators of facilities that are the site of a release of oil into regulated waters. OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. Spill prevention, control and countermeasure requirements under federal or state law may require appropriate operating protocols,

Table of Contents

including containment berms and similar structures, to help prevent or respond to a petroleum hydrocarbon spill, rupture or leak. In addition, the Clean Water Act and analogous state laws may require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities or during construction activities.

Hydraulic Fracturing. It is customary to recover oil and natural gas from deep shale, tight sand and coal bed formations through the use of hydraulic fracturing, combined with sophisticated horizontal drilling. Conventional hydraulic fracturing techniques are used to increase production in vertical wells. Hydraulic fracturing involves the injection of water, sand and chemical additives under pressure into rock formations to stimulate gas production. The federal Energy Policy Act of 2005 amended the Underground Injection Control provisions of the federal Safe Drinking Water Act to exclude certain hydraulic fracturing activities from the definition of "underground injection." At present, hydraulic fracturing is regulated at the state and local level. Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal, state and local level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Repeal of the exemption would allow EPA to promulgate new regulations. Many states have adopted rules that required operators to disclose chemicals and water volumes associated with hydraulic fracturing. In addition, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with final results expected in 2014.

Air Emissions. The federal Clean Air Act, and comparable state laws, restrict the emission of air pollutants from many sources, including drilling operations and related equipment, and as a result affect oil and natural gas operations. EPA has also developed, and continues to give attention to, stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and gas operations. Air emissions permits may be required for some oil and gas production operations.

Climate Change. In the recent Congressional session, numerous legislative measures were introduced that would have imposed restrictions or costs on greenhouse gas emissions, including from the oil and gas industry. It is uncertain whether similar measures will be introduced in, or passed by, the new Congress. However, any such legislation may have the potential to affect oil and gas production and the energy sector generally. The EPA has determined that greenhouse gases from certain sources "endanger" public health or welfare. As a result, the EPA has begun to promulgate certain regulations and interpretations that will require new and modified stationary source of greenhouse gases above certain thresholds to report, limit or control such emissions. Currently, certain oil and gas operations must inventory and report green house gas emissions. The EPA has determined that greenhouse gases from certain sources "endanger" public health or welfare. As a result, the EPA has begun to promulgate certain regulations and interpretations that will require new and modified stationary sources of greenhouse gases above certain thresholds to report, limit or control such emissions. Certain oil and gas operations must inventory and report greenhouse gas emissions. Although subject to legal challenge, the EPA rules promulgated thus far are currently final and effective and will remain so unless overturned by a court, or unless Congress adopts legislation altering the EPA's regulatory authority. The EPA has also announced its intention to promulgate additional regulations restricting greenhouse gas emissions, including rules applicable to the power generation sector and oil refining sector, which may affect demand for oil and gas. In addition, some states have taken or proposed legal measures to reduce emissions of greenhouse gases. For example, a number of states, including states in which the Royalty Properties are located, have indicated an intent to reduce greenhouse gases through state action or regional partnerships. New Mexico joined the Western Climate Initiative, or "WCI," a regional organization that has committed to take measures to reduce greenhouse gas emissions, and Kansas, Wyoming and Colorado have joined the WCI as observers.

Table of Contents

Safety. The working interest owners are also subject to the requirements of the federal Occupational Safety and Health Act, known as "OSHA," and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that information be maintained about hazardous materials used or produced by oil and gas operations and that this information be provided to employees, state and local government authorities and the public.

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.

Oil and 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.

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

political conditions worldwide, in particular political disruption, war or other armed conflicts in oil producing regions;

worldwide economic conditions;

weather conditions;

the supply and price of foreign natural gas;

the level of consumer demand;

the price and availability of alternative fuels;

the proximity to, and capacity of, transportation facilities; and

the effect of worldwide energy conservation measures.

Moreover, government regulations, such as regulation of natural gas transportation, regulation of greenhouse gas and other emissions associated with fossil fuel combustion, and price controls, can affect product prices in the long term.

Crude oil prices have been volatile the last several years and, in 2012, ranged from a high of approximately $109.39 to a low of approximately $77.72 The Trust cannot predict the timing or the duration of any economic cycle and, depending on the prices realized, the financial condition of the Trust could be materially adversely affected.

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.

Table of Contents

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. Accordingly, there may not be sufficient net proceeds to make a particular distribution.

The Trust may establish a cash reserve for contingent liabilities and to pay expenses in accordance with the Trust Indenture, which would reduce Net Proceeds available to the Trust and distributions to Trust unitholders.

The Trust's source of capital is the Royalty income received from its share of the net proceeds from the Royalty Properties. Pursuant to the Trust Indenture, the Trust may establish a cash reserve through the withholding of cash for contingent liabilities and to pay expenses. For example, effective January 1, 2011, the Trustee established a cash reserve for contingent liabilities and expenses in accordance with the Trust Indenture and withheld approximately $83,333 per monthly distribution amount, or up to $250,000 per quarter, until the cash reserve was $1.0 million, which reduced net proceeds available to the Trust and distributions to Trust unitholders. For more information, 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.

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

Table of Contents

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.

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.

Table of Contents

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 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.

The working interest owners' operations are subject to environmental, health and safety laws and regulations that may expose the working interest owners to penalties, damages or costs of remediation or compliance which could adversely affect Trust distributions.

The working interest owners' operations are subject to federal, regional, state and local laws and regulations relating to protection of natural resources and the environment, health and safety aspects of oil and gas operations and waste management, including the transportation and disposal of waste and other materials. These laws and regulations may impose numerous obligations on such operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital expenditures to mitigate or prevent releases of materials from facilities, the imposition of substantial liabilities for pollution resulting from operations and the application of specific health and safety criteria addressing worker protection. Failure to comply with these laws and regulations could result in restrictions or orders suspending well operations, the assessment of administrative, civil and criminal penalties, the revocation of permits and the issuance of corrective action orders.

There is inherent risk of environmental costs and liabilities in the oil and gas business as a result of the handling of petroleum hydrocarbons and oilfield and industrial wastes, air emissions and wastewater discharges related to current operations as well as historical industry operations and waste disposal practices. Some environmental laws and regulations may impose strict liability, which means that in some situations, the working interest owners could be exposed to liability as a result of conduct that was without fault or lawful at the time it occurred or as a result of the conduct of, or conditions caused by, prior operators or other third parties. Clean-up costs and other damages arising as a result

Table of Contents

of environmental laws and costs associated with changes in environmental laws and regulations could be substantial and could have a material adverse effect on Trust distributions.

Laws protecting the environment generally have become more stringent over time and are expected to continue to do so, which could lead to material increases in costs for future environmental compliance and remediation. The modification or interpretation of existing laws or regulations, or the adoption of new laws or regulations, could curtail exploratory or developmental drilling for oil and natural gas. The working interest owners may not be able to recover some or any of such costs of compliance with these laws and regulations from insurance.

Please read "Business Environmental Matters" for more information on the environmental laws and government regulations that may be applicable to the working interest owners' operations.

Climate change legislation or regulations restricting or regulating emissions of greenhouse gases could result in increased operating costs and could adversely affect Trust distributions.

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases from industrial and energy sources contribute to increases of carbon dioxide levels in the earth's atmosphere and oceans and contribute to global warming and other environmental effects, the EPA has adopted various regulations under the federal Clean Air Act addressing emissions of greenhouse gases that may affect the oil and gas industry, including mandatory reporting. Such changes will affect state air permitting programs in states that administer the federal Clean Air Act under a delegation of authority, including states in which the Royalty Properties are located. Some states have also indicated an intent to regulate or impose restrictions or costs on greenhouse gas emissions or fossil fuels. The adoption and implementation of any international treaty or of any federal or state legislation or regulations imposing restrictions on emissions of greenhouse gases could require the working interest owners to incur costs to comply with such requirements and possibly require the reduction or limitation of emissions of greenhouse gases associated with the working interest owners' operations or could impose costs on other sources of emissions within the industrial or energy sectors. Such legislation or regulations could adversely affect demand for the production of oil and natural gas and increase operating costs by requiring additional expenditures to operate and maintain equipment and facilities, inventory emissions, install emissions controls, acquire allowances or pay taxes and fees relating to emissions, which could adversely affect Trust distributions. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases may produce changes in climate or weather, such as increased frequency and severity of storms, floods, drought and other climatic events, which if any such effects were to occur, could have adverse physical effects on the working interest owners' operations or physical assets.

Please read "Business Environmental Matters" for more information on the environmental laws and government regulations that may be applicable to the working interest owners' operations.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays on the Royalty properties in which the Trust holds an interest.

Congress has considered legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas wells in shale and coal formations, as well as tight conventional formations including many of those Royalty properties in which the Trust holds an interest. This process involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Sponsors of these bills have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. In addition, some states have adopted and others are considering legislation to

Table of Contents

restrict hydraulic fracturing. Several states including those where Royalty properties are located have adopted legislation requiring the public disclosure of hydraulic fracturing chemicals, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. Further, the EPA has initiated a study of the impacts of hydraulic fracturing with final results expected in 2014. In addition, any additional level of regulation could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business and required disclosure without protection for trade secret or proprietary products could discourage service companies from using such products and as a result impact the degree to which some oil and gas wells may be efficiently and economically completed or brought into production.

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. Information regarding operations has been subject to errors and adjustments in the past. Accordingly, the Trustee cannot assure unitholders that other errors or adjustments by working interest owners, whether historical or future, will not affect Royalty income and distributions by the Trust.

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 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.

Table of Contents

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

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

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

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

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

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

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

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

Unitholders have limited voting rights.

Voting rights as a unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of unitholders or for an annual or other periodic re-election of the Trustee. Additionally, Trust unitholders have no voting rights in Pioneer or ConcoPhillips. Unlike corporations which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a corporate Trustee in accordance with the

Table of Contents

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. Mine Safety Disclosures.

Not applicable.

Table of Contents

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, 2012 and December 31, 2011, were as follows:

	2012			2011		
Quarter	High	Low	Distribution	High	Low	Distribution
First	$ 43.50	$ 36.46	$ 0.6445	$ 50.55	$ 45.91	$ 0.6135
Second	$ 39.71	$ 25.00	$ 0.4728	$ 49.90	$ 39.70	$ 0.6493
Third	$ 34.12	$ 22.93	$ 0.3696	$ 49.50	$ 39.69	$ 0.9671
Fourth	$ 27.45	$ 18.75	$ 0.4456	$ 45.00	$ 38.99	$ 0.7255

At March 29, 2013, the 1,863,590 units outstanding were held by 840 unitholders of record.

Item 6. Selected Financial Data.

	2012	2011	2010	2009	2008
Royalty income	$ 3,781,422	$ 6,661,178	$ 6,686,481	$ 4,052,357	$ 13,845,456
Distributable income	$ 3,601,394	$ 6,507,541	$ 6,521,193	$ 3,844,464	$ 13,768,502
Distributable income per unit	$ 1.9325	$ 2.9554	$ 3.4992	$ 2.0629	$ 7.3882
Total assets at year end	$ 6,332,055	$ 7,438,593	$ 6,948,580	$ 7,580,604	$ 9,966,534

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.

Table of Contents

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.

The Trustee has engaged an independent consulting firm to audit revenues, expenses and established reserves of certain working interest owners. These reviews and audits are ongoing. While these audits have highlighted issues that remain open, the Trustee has not made a determination at this time whether any audit exceptions will result in any material gains or expenses net to the Trust.

Effective January 1, 2011, the Trustee began withholding $83,333 of cash per month for future unknown contingent liabilities and expenses in accordance with the Trust Indenture. The cash withholding was established through the withholding of cash received during 2011 of approximately $83,333 per monthly distribution amount, or up to $250,000 per quarter, until the cash withholding reached $1.0 million. At December 31, 2011, the Trust withheld a total of $1.0 million which is included in cash and short term investments. The effect on distributable income per unit is as follows:

	Twelve Months Ended December 31,	
	2012	**2011**
Distributable Income Before Reserve for Contingent Liabilities and Expenses	$ 3,601,394	$ 6,507,541
Reserve for Contingent Liabilities and Expenses		(1,000,000)
Distributable Income Available for Distribution	$ 3,601,394	$ 5,507,541
Distributable Income Per Unit	$ 1.9325	$ 2.9554
Units Outstanding	1,863,590	1,863,590

Table of Contents

Financial Review

Years 2012 and 2011

	Years Ended December 31,	
	2012	2011
Royalty income	$ 3,781,422	$ 6,661,178
Interest income	80,175	116
General and administrative expenses	(260,203)	(153,753)
Distributable income	$ 3,601,394	$ 6,507,541
Distributable income per unit	$ 1.9325	$ 2.9554

The Trust's Royalty income was $3,781,422 in 2012, a decrease of approximately 43% as compared to $6,661,178 in 2011, primarily as a result of lower prices for natural gas and natural gas liquids. The Trust's Interest income in 2012 was $80,175, an increase from $116 in 2011. In accordance with the Trust Indenture, interest on cash on hand was paid at a rate of 1.5% below the prime interest rate. In addition, General and Administrative expense increased to $260,203 in 2012 compared with $153,753 in 2011. The increase was a result of joint venture auditor costs incurred in the Trustee's review of certain information and calculations by the working interests owners.

Hugoton Field

Royalty income attributable to the Hugoton Royalty Properties was $1,447,723 in 2012, a decrease of approximately 46%, as compared to $2,691,646 in 2011, primarily due to decreases in prices for natural gas and natural gas liquids, offset in part by a decrease in capital expenditures.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $3.03 per Mcf and $37.99 per barrel, respectively, in 2012 as compared to $4.28 per Mcf and $51.95 per barrel, respectively, in 2011. Net production attributable to the Hugoton Royalty was 274,488 Mcf of natural gas and 16,215 barrels of natural gas liquids in 2012 as compared with 375,914 Mcf of natural gas and 20,842 barrels of natural gas liquids in 2011. Actual production volumes attributable to the Hugoton properties were 519,967 Mcf of natural gas and 30,797 barrels of natural gas liquids in 2012 as compared with 565,753 Mcf of natural gas and 30,808 of natural gas liquids in 2011. The decrease in natural gas production for the year ended December 31, 2012 compared to the same period in 2011 is the result of natural production decline.

The Hugoton capital expenditures were $6,220 for 2012, a decrease of approximately 94% as compared to $102,315 for 2011, due to a decrease in the drilling activity in 2012 compared to 2011. Operating costs were $1,288,440 during 2012, an increase of approximately 5% as compared to $1,226,690 during 2011 due to an increase in labor and supervision costs.

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 $2,041,810 in 2012 as compared to $3,564,205 in 2011, a decrease of 43%. The decrease in Royalty income was due primarily to decreased natural gas and natural gas liquids prices in 2012 and an increase in capital expenditures, offset in part by lower operating expenditures in 2012. Net production attributable to the San Juan Basin Royalty located in the state of New Mexico was 363,314 Mcf of natural gas and 44,195 barrels of natural gas liquids, oil and condensate in 2012 as compared to 503,920 Mcf of natural gas and 56,439 barrels of natural gas liquids, oil and condensate in 2011. Actual production attributable to the San Juan Basin properties located in the state of New Mexico was 713,857 Mcf of natural gas and 93,135 barrels of natural gas liquids, oil and condensate in

Table of Contents

2012 as compared with 747,397 Mcf of natural gas and 90,077 barrels of natural gas liquids, oil and condensate in 2011. 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 $2.02 per Mcf and $29.59 per barrel, respectively, in 2012 compared with $2.99 per Mcf and $36.46 per barrel, respectively, in 2011.

San Juan New Mexico capital expenditures were $761,653 during 2012, an increase of approximately 72% as compared to $443,976 during 2011. The increase in capital expenditures was due to an increase in drilling activity. Operating costs were $1,268,973 during 2012, a decrease of approximately 4% as compared to $1,323,187 during 2011.

Royalty income from the San Juan Basin Colorado Royalty Properties was $291,889 in 2012 as compared to $465,327 in 2011. The decrease in royalty income was primarily the result of lower natural gas prices in 2012. Net production attributable to the San Juan Basin Royalty properties primarily located in Colorado was 167,826 Mcf of natural gas in 2012 as compared to 167,176 Mcf of natural gas in 2011. The average price received for natural gas from these San Juan Basin properties was $1.74 per Mcf in 2012 as compared with $2.78 per Mcf in 2011. Actual natural gas production volumes attributable to the San Juan Basin Colorado Properties were 216,213 Mcf in 2012 as compared with 197,879 Mcf in 2011. There was no actual or net production of natural gas liquids or oil and condensate from the San Juan Basin, Colorado Properties during 2012 and 2011.

Years 2011 and 2010

	Years Ended December 31,	
	2011	**2010**
Royalty income	$ 6,661,178	$ 6,686,481
Interest income	116	179
General and administrative expenses	(153,753)	(165,467)
Distributable income	$ 6,507,541	$ 6,521,193
Distributable income per unit	$ 2.9554	$ 3.4992

The Trust's Royalty income was $6,661,178 in 2011, a decrease of approximately .4% as compared to $6,686,481 in 2010, primarily as a result of higher prices for natural gas liquids, offset in part by lower prices for natural gas.

Hugoton Field

Royalty income attributable to the Hugoton Royalty Properties was $2,691,646 in 2011, a decrease of approximately 4%, as compared to $2,795,973 in 2010, primarily due to decreases in prices for natural gas and capital costs, offset in part by increases in prices for natural gas liquids during 2011 and an increase in operating costs primarily due to the severance tax refund filed with the state of Kansas and already paid to the Trust during 2010 which amounted to $166,615.

The average price received for natural gas and natural gas liquids from the Hugoton Royalty Properties was $4.28 per Mcf and $51.95 per barrel, respectively, in 2011 as compared to $4.67 per Mcf and $42.34 per barrel, respectively, in 2010. Net production attributable to the Hugoton Royalty was 375,914 Mcf of natural gas and 20,842 barrels of natural gas liquids in 2011 as compared with 393,420 Mcf of natural gas and 22,644 barrels of natural gas liquids in 2010. Actual production volumes attributable to the Hugoton properties were 565,753 Mcf of natural gas and 30,808 barrels of natural gas liquids in 2011 as compared with 568,922 Mcf of natural gas and 32,911 of natural gas liquids in 2010. The decrease in natural gas production for the year ended December 31, 2011 compared to the same period in 2010 is the result of natural production decline.

Table of Contents

The Hugoton capital expenditures were $102,315 for 2011, a decrease of approximately 50% as compared to $206,023 for 2010, due to a decrease in the drilling activity in 2011 compared to 2010. Operating costs were $1,226,690 during 2011, an increase of approximately 17% as compared to $1,047,193 during 2010 due to the severance tax refund filed with the state of Kansas and already paid to the Trust in 2010 and a decrease in ad valorem taxes.

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 $3,564,205 in 2011 as compared to $3,530,917 in 2010, an increase of 1%. The increase in Royalty income was due primarily to increased natural gas liquids prices in 2011, offset by increased capital and operating expenditures and decreased prices for natural gas in 2011. Net production attributable to the San Juan Basin Royalty located in the state of New Mexico was 503,920 Mcf of natural gas and 56,439 barrels of natural gas liquids, oil and condensate in 2011 as compared to 572,489 Mcf of natural gas and 49,134 barrels of natural gas liquids, oil and condensate in 2010. Actual production attributable to the San Juan Basin properties located in the state of New Mexico was 747,397 Mcf of natural gas and 90,077 barrels of natural gas liquids, oil and condensate in 2011 as compared with 850,375 Mcf of natural gas and 82,955 barrels of natural gas liquids, oil and condensate in 2010. 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 $2.99 per Mcf and $36.46 per barrel, respectively, in 2011 compared with $3.30 per Mcf and $29.51 per barrel, respectively, in 2010.

San Juan New Mexico capital expenditures were $443,976 during 2011, an increase of approximately 10% as compared to $404,462 during 2010. The increase in capital expenditures was due to an increase in drilling activity. Operating costs were $1,323,187 during 2011, an increase of approximately .4% as compared to $1,317,853 during 2010. Royalty income from the San Juan Basin Colorado Royalty Properties was $465,327 in 2011 as compared to $299,553 in 2010. The increase in royalty income was primarily the result of higher natural gas production and decreased operating expenditures in 2011, offset in part by lower natural gas prices. Net production attributable to the San Juan Basin Royalty properties primarily located in Colorado was 167,176 Mcf of natural gas in 2011 as compared to 97,760 Mcf of natural gas in 2010. The average price received for natural gas from these San Juan Basin properties was $2.78 per Mcf in 2011 as compared with $3.06 per Mcf in 2010. Actual natural gas production volumes attributable to the San Juan Basin Colorado Properties were 197,879 Mcf in 2011 as compared with 147,965 Mcf in 2010. There was no actual or net production of natural gas liquids or oil and condensate from the San Juan Basin, Colorado Properties during 2011 and 2010.

Table of Contents

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

	Hugoton		San Juan New Mexico		San Juan 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, 2012:								
The Trust's proportionate share of Gross Proceeds(1)	$ 1,573,087	$ 1,169,296	$ 1,443,257	$ 2,629,179	$ 379,606	$	$ 3,395,950	$ 3,798,475
Less the Trust's proportionate share of Capital costs	(3,124)	(3,096)	(255,783)	(505,870)			(258,907)	(508,966)
Operating costs	(738,265)	(550,175)	(453,445)	(815,528)	(87,717)		(1,279,427)	(1,365,703)
Net Proceeds(2)	$ 831,698	$ 616,025	$ 734,029	$ 1,307,781	$ 291,889	$	$ 1,857,616	$ 1,923,806
Royalty Income(2)								
Average Sales Price	$ 3.03	$ 37.99	$ 2.02	$ 29.59	$ 1.74	$	$ 2.31	$ 31.85
Average Production Costs(3)	$ 2.70	$ 34.12	$ 1.95	$ 29.90	$ .52	$	$ 1.91	$ 31.03
Net production volumes attributable to the	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Royalty paid(4)	274,488	16,215	363,314	44,195	167,826		805,628	60,410
Year ended December 31, 2011:								
The Trust's proportionate share of Gross Proceeds(1)	$ 2,421,031	$ 1,599,620	$ 2,235,840	$ 3,095,528	$ 552,263	$	$ 5,209,134	$ 4,695,148
Less the Trust's proportionate share of Capital costs	(68,195)	(34,120)	(181,073)	(262,903)			(249,268)	(297,023)
Operating costs	(743,923)	(482,767)	(548,045)	(775,142)	(86,936)		(1,378,904)	(1,257,909)
Net Proceeds(2)	$ 1,608,913	$ 1,082,733	$ 1,506,722	$ 2,057,483	$ 465,327	$	$ 3,580,962	$ 3,140,216
Royalty Income(2)(5)	1,608,913	1,082,733	1,506,722	2,057,483	465,327		3,580,962	3,140,217
Average Sales Price	$ 4.28	$ 51.95	$ 2.99	$ 36.46	$ 2.78	$	$ 3.42	$ 40.63
Average Production Costs(3)	$ 2.16	$ 24.80	$ 1.45	$ 18.39	$ .52	$	$ 1.56	$ 20.12
Net production volumes attributable to the	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Royalty paid(4)	375,914	20,842	503,920	56,439	167,176		1,047,010	77,281
Year ended December 31, 2010:								
The Trust's proportionate share of Gross Proceeds(1)	$ 2,656,667	$ 1,392,560	$ 2,805,331	$ 2,447,901	$ 507,558	$	$ 5,969,556	$ 3,840,461
Less the Trust's proportionate share of Capital costs	(135,053)	(70,970)	(216,558)	(187,904)			(351,611)	(258,874)
Operating costs	(684,342)	(362,851)	(699,557)	(618,296)	(208,005)		(1,591,904)	(981,147)
Net Proceeds(2)	$ 1,837,272	$ 958,739	$ 1,889,216	$ 1,641,701	$ 299,553	$	$ 4,026,041	$ 2,600,440
Royalty Income(2)	1,837,272	958,739	1,889,216	1,641,701	299,553		4,026,041	2,600,440
Average Sales Price	$ 4.67	$ 42.34	$ 3.30	$ 33.41	$ 3.06	$	$ 3.79	$ 36.23
Average Production Costs(3)	$ 2.08	$ 19.15	$ 1.60	$ 16.41	$ 2.13	$	$ 1.83	$ 17.28

Net production volumes attributable to the	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Royalty paid(4)	393,420	22,644	572,489	49,134	97,760		1,063,668	71,778

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

(2) 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.

(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.

(5) Due to an adjustment of $60,000 to royalty income at December 31, 2010, the natural gas royalty income and oil, condensate and natural gas liquids royalty income may not agree to the twelve months ended December 31, 2011 royalty income.

Table of Contents

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.

Table of Contents

Item 8. Financial Statements and Supplementary Data.

MESA ROYALTY TRUST
STATEMENTS OF DISTRIBUTABLE INCOME

	Years Ended December 31,		
	2012	**2011**	**2010**
Royalty income	3,781,422	$ 6,661,178	$ 6,686,481
Interest income	80,175	116	179
General and administrative expenses	(260,203)	(153,753)	(165,467)
Distributable income	$ 3,601,394	$ 6,507,541	$ 6,521,193
Distributable income per unit	$ 1.9325	$ 2.9554	$ 3.4992

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31,	
	2012	**2011**
ASSETS		
Cash and short-term investments	$ 1,830,390	$ 2,351,895
Net overriding royalty interests in oil and gas properties	42,498,034	42,498,034
Less: accumulated amortization	(38,013,221)	(37,411,336)
Total assets	$ 6,315,203	$ 7,438,593
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 830,390	$ 1,351,895
Trust corpus (1,863,590 units of beneficial interest authorized and outstanding)	5,484,813	6,086,689
Total liabilities and trust corpus	$ 6,315,203	$ 7,438,593

STATEMENTS OF CHANGES IN TRUST CORPUS

	Years Ended December 31,		
	2012	**2011**	**2010**
Trust corpus, beginning of year	$ 6,086,698	$ 5,557,747	$ 6,386,000
Distributable income	3,601,394	6,507,541	6,521,193
Distributions to unitholders	(3,601,394)	(5,507,541)	(6,521,193)
Amortization of net overriding royalty interests	(601,885)	(471,049)	(828,253)
Trust corpus, end of year	$ 5,484,813	$ 6,086,698	$ 5,557,747

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

Table of Contents

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

Table of Contents

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.

Effective January 1, 2011, the Trustee began withholding $83,333 of cash per month for future unknown contingent liabilities and expenses in accordance with the Trust Indenture. The cash withholding was established through the withholding of cash received during 2011 of approximately $83,333 per monthly distribution amount, or up to $250,000 per quarter, until the cash withholding reached $1.0 million. At December 31, 2011, the Trust had withheld a total of $1.0 million which is included in cash and short term investments. The effect on distributable income per unit is as follows:

	Twelve Months Ended December 31,	
	2012	2011
Distributable Income Before Reserve for Contingent Liabilities and Expenses	$ 3,601,394	$ 6,507,541
Reserve for Contingent Liabilities and Expenses		(1,000,000)
Distributable Income Available for Distribution	$ 3,601,394	$ 5,507,541
Distributable Income Per Unit	$ 1.9325	$ 2.9554
Units Outstanding	1,863,590	1,863,590

For the year ended December 31, 2012, The Bank of New York Mellon Trust Company, N.A. was paid fees totaling $337,302 in connection with services performed in its capacity as Trustee. These fees have been reimbursed by the working interest owners in accordance with the Trust Indenture. These reimbursements totaled $227,859.

(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.

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(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 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.

Effective January 1, 2011, the Trustee began withholding $83,333 of cash per month for future unknown contingent liabilities and expenses in accordance with the Trust Indenture. The cash withholding was established through the withholding of cash received during 2011 of approximately $83,333 per monthly distribution amount, or up to $250,000 per quarter, until the cash withholding

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(4) Distributions to Unitholders (Continued)

reached $1.0 million. At December 31, 2011, the Trust had withheld a total of $1 million which is included in cash and short term investments. The effect on distributable income per unit is as follows:

	Twelve Months Ended December 31,	
	2012	2011
Distributable Income Before Reserve for Contingent Liabilities and Expenses	$ 3,601,394	$ 6,507,541
Reserve for Contingent Liabilities and Expenses (See Note 1)		(1,000,000)
Distributable Income Available for Distribution	$ 3,601,394	$ 5,507,541
Distributable Income Per Unit	$ 1.9325	$ 2.9554
Units Outstanding	1,863,590	1,863,590

(5) 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. In addition, there is no state tax liability for the year.

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. Notwithstanding the foregoing, the middlemen holding units on behalf of unitholders, and not the Trustee of the Trust, are solely responsible for complying with the information reporting requirements under the Treasury Regulations with respect to such units, including the issuance of IRS Forms 1099 and certain written tax statements.

(6) 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.

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(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 2010 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 $0 and $0 as of December 31, 2012 and 2011, respectively. 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. On March 25, 2010, the Kansas Department of Revenue issued a final assessment, which included additional interest and penalties, increasing the amount assessed to approximately $4.5 million. The portion of the tax assessment net to the Trust is approximately $197,000, which could adversely affect Trust distributions. On June 24, 2011, the hearing examiner of the Department of Revenue upheld the earlier assessment. PNR has filed an appeal to the Court of Tax Appeals in Kansas. No assurance can be made that any objections or disputed items raised by PNR will be successful.

On December 9, 2011, PNR and the Kansas Department of Revenue entered into a settlement of the Department of Revenue's assessment. The settlement amount was $2 million, which is less than 50% of the amount of the assessment. As a result of the settlement, the appeal of the assessment pending before the Court of Tax Appeals was dismissed on December 20, 2011. The portion of the tax assessment net to the Trust is $84,719 and was withheld from the cash available for distribution in January 2012.

(9) Supplemental Reserve Information (Unaudited)

Effective for fiscal years ending on or after December 31 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

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(9) Supplemental Reserve Information (Unaudited) (Continued)

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

Estimates of the proved oil and gas reserves attributable to the Hugoton and San Juan Basin Royalty Properties as of December 31, 2012, 2011, 2010 and 2009 are based on reports prepared by DeGolyer and MacNaughton, independent petroleum engineering consultants. The estimates were prepared in accordance with guidelines established by 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, 2012, 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. Operating costs, production and ad valorem taxes and future development and abandonment costs were based on current costs as of each year end, with no escalation.

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

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

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

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(9) Supplemental Reserve Information (Unaudited) (Continued)

ESTIMATED QUANTITIES OF PROVED AND PROVED DEVELOPED RESERVES
(Unaudited)

	Oil, Condensate and Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Reserves:		
December 31, 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
Revisions to previous estimates	609,575	8,557,374
Extensions, discoveries and other additions		
Production	(71,778)	(1,063,668)
December 31, 2010	1,022,747	14,373,359
Revisions to previous estimates	(372,684)	(5,330,922)
Extensions, discoveries and other additions		
Production	(77,281)	(1,047,010)
December 31, 2011	572,782	7,995,427
Revisions to previous estimates	(192,717)	(3,518,637)
Extensions, discoveries and other additions		
Production	(60,410)	(805,628)
December 31, 2012	297,927	4,014,127
Proved Developed Reserves:		
December 31, 2008	609,971	9,532,466
December 31, 2009	478,913	6,773,482
December 31, 2010	999,350	13,961,912
December 31, 2011	535,742	7,344,057
December 31, 2012	278,984	3,681,019
Proved Undeveloped Reserves:		
December 31, 2008		

December 31, 2009	6,037	106,171
December 31, 2010	23,397	411,447
December 31, 2011	37,040	651,370
December 31, 2012	18,942	333,108

The Hugoton Royalty represents 17%, 26%, and 32% of the estimated proved oil, condensate and natural gas liquids reserves and 13%, 33%, and 39% of the estimated proved natural gas reserves as of December 31 of 2012, 2011 and 2010, respectively.

The December 31, 2012, 2011, 2010 and 2009 reserve estimates for the Hugoton properties were prepared by a third party reservoir engineering firm. Revisions in previous estimates in 2009 are primarily due to decreases in natural gas and natural gas liquid prices.

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(9) Supplemental Reserve Information (Unaudited) (Continued)

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

	December 31,		
	2012	2011	2010
	(In thousands)		
The Trust's proportionate share of future gross proceeds	$ 55,638	$ 102,707	$ 114,214
Less the Trust's proportionate share of Future operating costs	(33,381)	(46,898)	(16,084)
Future capital costs	(2,057)	(2,673)	(1,186)
Future royalty income	20,200	53,136	96,944
Discount at 10% per annum	(8,494)	(23,199)	(52,134)
Standardized measure of future royalty income from proved oil and gas reserves	$ 11,706	$ 29,937	$ 44,810

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

	December 31,		
	2012	2011	2010
	(In thousands)		
Standardized measure at beginning of year	$ 29,937	$ 44,810	$ 17,811
Revisions of previous estimates	(2,874)	2,594	2,594
Net changes in price and production costs	(14,294)	(12,587)	29,310
Extensions, discoveries and other additions			
Royalty income	(3,781)	(6,661)	(6,686)
Accretion of discount	2,718	1,781	1,781
Net changes in standardized measure	(18,231)	(14,873)	26,999
Standardized measure at end of year	$ 11,706	$ 29,937	$ 44,810

The Hugoton Royalty represents approximately 22% and 40% of the standardized measure of future royalty income for 2012 and 2011, respectively.

Standardized measure at December 31, 2012 was calculated using natural gas prices of $3.01 per Mcf for Hugoton properties and $2.04 for the San Juan properties.

39

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(9) Supplemental Reserve Information (Unaudited) (Continued)

Selected Quarterly Financial Data (Unaudited)

	Summarized Quarterly Results Three Months Ended			
	March 31	**June 30**	**September 30**	**December 31**
2012:				
Royalty income	$ 1,269,367	$ 919,695	$ 737,229	$ 855,131
Distributable income	$ 1,201,144	$ 881,051	$ 688,809	$ 830,390
Distributable income per unit	$ .6445	$ .4728	$ .3696	$ .4456
2011:				
Royalty income	$ 1,439,204	$ 1,503,570	$ 2,081,025	$ 1,637,379
Distributable income	$ 1,393,339	$ 1,460,069	$ 2,052,238	$ 1,601,895
Distributable income per unit	$ .6135	$ .6493	$ .9671	$ .7255

Table of Contents

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, 2012 and 2011, 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, 2012. 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 the Trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 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, 2012 and 2011, and the distributable income and changes in trust corpus for each of the years in the three-year period ended December 31, 2012, 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, 2012, 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 29, 2013 expressed an unqualified opinion on the effectiveness of Mesa Royalty Trust's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
March 29, 2013

Table of Contents

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, 2012, 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, included in the accompanying *Trustee's Report on 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.

The Trust'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 the cash receipts and disbursements basis of accounting. The Trust'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 Trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the cash receipts and disbursements basis of accounting, and that receipts and expenditures of the Trust are being made only in accordance with authorizations of the Trustee; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Trust'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, 2012, 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, 2012 and 2011, 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, 2012, and our report dated March 29, 2013 expressed an unqualified opinion on those financial statements.

/s/ KPMG LLP

Houston, Texas
March 29, 2013

Table of Contents

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 certain annual and quarterly reports on Form 10-K and on Form 10-Q prior to 2011, 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. 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.

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*

Table of Contents

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, 2012. The Trustee's assessment of the effectiveness of the Trust's internal control over financial reporting as of December 31, 2012 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.

Table of Contents

Section 16(a) Beneficial Ownership Reporting Compliance.

The Trust has no directors or officers. Accordingly, only holders of more than 10% of the Trust's units are required to file with the SEC initial reports of ownership of Units and reports of changes in such ownership pursuant to Section 16 under the Securities Exchange Act of 1934. Based solely on a review of these reports, the Trust believes that the applicable reporting requirements of Section 16(a) of the Securities Exchange Act of 1934 were complied with for all transactions that occurred in 2012.

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.

Not applicable.

(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.

The following table presents fees for professional audit services rendered by KPMG LLP for the audit of the Mesa Royalty Trust financial statements for 2012 and 2011 and fees billed for other services rendered by KPMG LLP.

	2012	2011
Audit fees(1)	$ 475,000	$ 450,000
Audit-related fees		
Tax fees(2)	$ 82,245	$ 42,000
All other fees		
Total fees	$ 557,245	$ 492,000

(1) Audit fees consist of fees for the audit of the Mesa Royalty Trust financial statements, internal control over financial reporting and reimbursement for travel-related expenses related to the audit and quarterly reviews for the years ended December 31, 2012 and

December 31, 2011. 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 related to work performed on the taxes, returns and other items billed during 2012 and 2011. The Mesa Royalty Trust is reimbursed by the working interest owners for 88.56% of general and administrative expenses incurred.

Table of Contents

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.

	Page in this Form 10-K
Statements of Distributable Income	31
Statements of Assets, Liabilities and Trust Corpus	31
Statements of Changes in Trust Corpus	31
Notes to Financial Statements	32
Report of Independent Registered Public Accounting Firm KPMG LLP	41
Report of Independent Registered Public Accounting Firm KPMG LLP	42

(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		

Table of Contents

Exhibit Number		SEC File or Registration Number	Exhibit Number
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.

Table of Contents

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 29, 2013

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.

Table of Contents

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.

Table of Contents

Auditors	**Counsel**	**Transfer Agent and Registrar**
KPMG LLP Houston, Texas	Andrews Kurth LLP Houston, Texas	The Bank of New York Trust Company, N.A. Austin, Texas 78701

Mesa Royalty Trust
919 Congress Avenue
Suite 500
Austin, Texas 78701

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

Mesa Royalty Trust
The Bank of New York Trust Company, N.A.
Attention: Mike Ulrich, Institutional Trust Services
919 Congress Avenue, Suite 500
Austin, Texas 78701

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