MESA ROYALTY TRUST/TX
Form 10-K
April 02, 2018

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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, 2017

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 **Global Corporate Trust** **601 Travis Street, Floor 16** **Houston, Texas**	**77002**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **713-483-6020**

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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) if the Exchange Act. o

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

The aggregate market value of 1,863,590 Units of Beneficial Interest in Mesa Royalty Trust held by non-affiliates of the registrant at the closing sales price on June 30, 2017 of $11.70 was approximately $21,804,003.

As of April 2, 2018, 1,863,590 Units of Beneficial Interest were outstanding in Mesa Royalty Trust.

DOCUMENTS INCORPORATED BY REFERENCE: None

TABLE OF CONTENTS

DISCLOSURES REGARDING FORWARD-LOOKING STATEMENTS

This Form 10-K includes "forward-looking statements" about Mesa Royalty Trust (the "Trust") and other matters discussed herein that are subject to risks and uncertainties that are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995 and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical fact included in this document, including, without limitation, statements under "Management's Discussion and Analysis of Financial Condition and Results of Operations," including the Trust's or any Working Interest Owner's (as defined in "*Item 1 Description of the Trust*") future financial position, status in any insolvency proceeding, business strategy, budgets, projected costs and plans and objectives for future operations, information regarding target distributions, statements pertaining to future development activities and costs, statements regarding the number of development wells to be completed in future periods, and information regarding production and reserve growth, are forward-looking statements. Actual outcomes and results may differ materially from those projected. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "can," "foresee," "plan," "goal," "assume," "target," "should," "intend" or other words that convey the uncertainty of future events or outcomes. These statements are based on certain assumptions made by the Trust in light of its experience and perception of historical trends, current conditions and expected

Table of Contents

future developments, as well as other factors we believe are appropriate under the circumstances. The Trustee relies on the Working Interest Owners for information regarding the Subject Interests (as defined in "Description of the Trust" under Item 1), the Royalty (as defined in "Description of the Trust" under Item 1), and the Working Interest Owners themselves.

Although the Working Interest Owners have advised the Trust that they believe that the expectations reflected in the forward-looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to be correct. However, whether actual results and developments will conform with such expectations and predictions is subject to a number of risks and uncertainties, including the risk factors discussed in this Form 10-K, and those set forth from time to time in the Trust's filings with the Securities and Exchange Commission (the "SEC"), which could affect the future results of the energy industry in general, and the Trust and the Working Interest Owners in particular, and could cause those results to differ materially from those expressed in such forward-looking statements. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to or effects on the Working Interest Owners' businesses and the Trust. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in such forward-looking statements. The Trust undertakes no obligation to publicly update or revise any forward-looking statements, except as required by applicable law.

Table of Contents

PART I

Item 1. Business.

DESCRIPTION OF THE 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"), 601 Travis Street, Floor 16, Houston, Texas 77002. The telephone number of the Trust is 713-483-6020. The Bank of New York Mellon Trust Company, N.A., is the successor Trustee from JPMorgan Chase Bank, N.A., which is the successor by mergers to the originally named Trustee, Texas Commerce Bank National Association. The Trust has no employees. Administrative functions of the Trust are performed by the Trustee. The Trustee maintains a website for the Trust that makes available, free of charge, filings by the Trust with the Securities and Exchange Commission ("SEC") and other information. Any reports filed with the SEC are accessible free of charge through our website as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The Trust's website is http://mtr.investorhq.businesswire.com/.

Trust Corpus Description. The Mesa Royalty Trust (the "Trust") was created on November 1, 1979, and is now governed by the Mesa Royalty Trust Indenture (as amended, the "Trust Indenture"). Through a series of conveyances, assignments, and acquisitions, the Trust currently owns an overriding royalty interest (the "Royalty") equal to 11.44% of 90% of the Net Proceeds (as defined in the Conveyance and described below) attributable to the specified interest in certain producing oil and gas properties located in the:

- Hugoton field of Kansas (the "Hugoton Royalty Properties");
- San Juan Basin field of New Mexico (the "San Juan Basin New Mexico Properties"); and
- San Juan Basin field of Colorado (the "San Juan Basin Colorado Properties", and together with the "San Juan Basin New Mexico Properties, the "San Juan Basin Royalty Properties", and together with the Hugoton Royalty Properties and the San Juan Basin Royalty Properties, the "Royalty Properties").

Trust Corpus Conveyance History. On November 1, 1979, Mesa Petroleum Co., predecessor to Mesa Limited Partnership ("MLP"), which was the predecessor to MESA Inc., conveyed to the Trust 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 the Royalty Properties described above. The Royalty is evidenced by counterparts of an Overriding Royalty Conveyance, dated as of November 1, 1979 (the "Conveyance"). 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 1985 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.

Hugoton Royalty Properties. 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 were operated by PNR until December 31, 2014, at which point Linn Energy Holdings, LLC, a subsidiary of Linn Energy, LLC ("Old Linn") took over as operator. Pursuant to the bankruptcy proceedings and court-approved plans of reorganization involving

Table of Contents

Old Linn, which are described in detail below, Linn Energy, Inc. (together with its subsidiaries, "Linn") became the operator of the Hugoton Royalty Properties on February 28, 2017. Linn currently operates the Hugoton Royalty Properties.

San Juan Basin Colorado Properties. On April 30, 1991, MLP sold to Conoco, Inc. ("ConocoPhillips") its interests in the San Juan Basin Royalty Properties (the "San Juan Basin Sale"). The Trust's interest in the San Juan Basin Royalty Properties was conveyed from PNR's working interest in 31,328 net producing acres in northwestern New Mexico and southwestern Colorado. ConocoPhillips sold the portion of its interests in the San Juan Basin Colorado Properties to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company ("Red Willow") (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the San Juan Basin Colorado Properties to BP Amoco Company ("BP"), a subsidiary of BP p.l.c. BP and Red Willow currently operate the San Juan Basin Colorado Properties.

San Juan Basin New Mexico Properties. Starting from the date of the San Juan Basin Sale and ending on July 31, 2017, ConocoPhillips operated substantially all of the San Juan Basin New Mexico Properties, except an immaterial number of properties assigned to XTO Energy, Inc. ("XTO") effective January 1, 2005. On July 31, 2017, ConocoPhillips sold its San Juan Basin assets to Hilcorp San Juan LP ("Hilcorp"), an affiliate of Hilcorp Energy Company. Hilcorp currently operates the San Juan Basin New Mexico Properties. Effective September 2017, following Hilcorp's acquisition of Conoco's interests in the San Juan New Mexico Properties, Hilcorp continued to make an estimated payment of Net Proceeds to the Trust each month consistent with the monthly amount previously paid by ConocoPhillips. These estimated payments remain subject to reconciliation with respect to actual revenue, costs and net proceeds and the effects of pricing during the months after Hilcorp has completed its transition as owner of the San Juan New Mexico Properties. The reconciliation and true-up of the estimated payments for this transition period may affect the Trust's future receipt of Net Proceeds from Hilcorp.

As used in this report, Linn refers to the current operator of the Hugoton Royalty Properties, Hilcorp refers to the current operator of the San Juan Basin New Mexico Properties, and BP and Red Willow refers to the current co-operators of certain tracts of land included in the San Juan Basin Colorado Properties, unless otherwise indicated. The Royalty Properties are required to be operated by the Working Interest Owners (as defined below) 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.

Trustee and Terms of Trust Indenture. Effective October 2, 2006, the Trustee succeeded JPMorgan Chase Bank, N.A. as Trustee of the Trust. The Trust is a passive entity whose purposes are limited to: (1) converting the Royalty to cash, either by retaining it and collecting the proceeds of production (until production has ceased or the Royalty is otherwise terminated) or by selling or otherwise disposing of the Royalty and (2) distributing such cash, net of amounts for payments of liabilities to the Trust, to the unitholders. The Trust has no sources of liquidity or capital resources other than the revenues, if any, attributable to the Royalty and interest on cash held by the Trustee as a reserve for liabilities or for distribution. The terms of 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 by the unitholders;

Table of Contents

(c) the Trustee can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge 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 2 of the Notes to Financial Statements contained in Item 8 of this Form 10-K;

(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 two successive years is less than $250,000 per year or (ii) a vote by the unitholders in favor of termination. Upon termination of the Trust, the Trustee will sell for cash all the assets held in the Trust estate and make a final distribution to unitholders of any funds remaining after all Trust liabilities have been satisfied; and

(f) Linn, Hilcorp and BP (each, a "Working Interest Owner", and 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.

Linn Energy, LLC Reorganization. On May 11, 2016, Old Linn, LinnCo, LLC ("LinnCo"), an affiliate of Old Linn, and certain of Old Linn's direct and indirect subsidiaries (collectively with Old Linn and LinnCo, the "Debtors"), filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Court"). The Debtors' Chapter 11 cases were administered jointly under the caption *In re Linn Energy, LLC, et al.*, Case No. 16 60040.

On January 27, 2017, the Court entered the *Order Confirming (I) Amended Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and its Debtor Affiliates Other Than Linn Acquisition Company, LLC and Berry Petroleum Company, LLC and (II) Amended Joint Chapter 11 Plan of Reorganization of Linn Acquisition Company, LLC and Berry Petroleum Company, LLC,* which approved and confirmed the Amended Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and Its Debtor Affiliates Other Than Linn Acquisition Company, LLC and Berry Petroleum Company, LLC (the "Plan"). The Plan became effective on February 28, 2017 (the "Effective Date").

Pursuant to the Plan, on the Effective Date, all assets of Old Linn (other than equity interests in Linn Acquisition Company, LLC and Berry Petroleum Company, LLC) were conveyed to Linn, and LinnCo, LLC and Linn Energy, LLC were wound down and liquidated. Subsequent to the effectiveness of the Plan, Linn Energy, Inc. is now the reorganized successor to Old Linn. Under the Plan Supplement, as amended, filed with the Court, the Debtors assumed all executory contracts and unexpired leases with the Trust and Mesa Operating Limited Partnership as the counterparty. Furthermore, pursuant to the Plan, the royalty interests in the Hugoton Royalty Properties owned by the Trust shall be preserved and remain in full force and effect in accordance with the terms of the granting instruments or other governing documents.

Discussion of Net Proceeds. The Conveyance provides for a monthly computation of Net Proceeds. Net Proceeds is defined in the Conveyance as the "Gross Proceeds" received by the Working Interest Owners during a particular period, minus certain production 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" means 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. "Production costs" means, generally, costs incurred on an accrual basis by the Working Interest Owners in operating the Royalty Properties, including capital and non-capital costs. If production 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

Table of Contents

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.

DESCRIPTION OF THE UNITS

Each unit of beneficial interest 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 April 2, 2018.

Distributions

The Trustee determines for each month the amount of cash available for distribution to unitholders for such month (the "Monthly Distribution Amount"), which consists of the cash received from the Royalty during such month, minus the obligations of the Trust paid during such month as adjusted for changes during such month in any cash reserves established for the payment of contingent or future obligations of the Trust made by the Trustee. The Monthly Distribution Amount for each month is payable to unitholders of record on 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, pursuant to the Trust Indenture and in order to reduce the administrative expenses of the Trust, the Trustee does not distribute cash monthly. Instead, the Trustee makes distributions during January, April, July and October of each year. While distributions are only made four times per calendar year, the Trustee distributes to each person who was a unitholder of record on one or more of the immediately preceding three monthly record dates, an amount equal to the Monthly Distribution Amount for the month or months that such holder was a unitholder of record plus 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 1.5% below the greater of (i) the prime rate charged by The Bank of New York Mellon Trust Company, N.A. or (ii) 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. Interest income may vary significantly across different payment dates.

The Working Interest Owners reimburse the Trust for portions of the total expenses incurred each month. The portions of expenses incurred by the Trustee without reimbursement from the Working Interest Owners are unreimbursed expenses. Unreimbursed expenses for any reporting period and are

Table of Contents

included in general and administrative expenses, which results in a reduction of distributable income. As of December 31, 2017, there were $0 unreimbursed expenses.

The terms of the Trust Indenture provide, among other things, that the Trustee may establish cash reserves and borrow funds to pay liabilities of the Trust and may pledge assets of the Trust to secure payment of the borrowings. During 2011, the Trustee withheld $1.0 million for future unknown contingent liabilities and expenses in accordance with the Trust Indenture. At any given time, the amount currently reserved for such future unknown contingent liabilities and expenses (the "Contingent Reserve") is included in cash and short-term investments.

For the year ended December 31, 2017, the Trustee increased the Contingent Reserve by (i) $82,244 of Royalty income received from BP in March 2017 after the distribution to unitholders had been announced for the month of March 2017, which Royalty income was included in the April 2017 distribution to unitholders, (ii) $47,840 of Royalty income received from BP in June 2017 after the distribution to unitholders had been announced for the month of June 2017, which Royalty income was included in the July 2017 distribution to unitholders, (iii) $1,307 for the amount of September expected expense reimbursement cash receipts, received in October 2017, (iv) $49,211 of Royalty income received from BP in December 2017 after the distribution to unitholders had been announced for the month of December 2017, which Royalty income was included in the January 2018 distribution to unitholders, and (v) $70,460 of December 2017 expenses that were included in the distribution calculation for December 2017, but not paid by the Trust until January 2018. For the year ended December 31, 2017, the Trustee decreased the Contingent Reserve by (i) $82,244 and $47,840 of aggregate Royalty income received from BP in March 2017 and June 2017, respectively, and (ii) $1,307 for expected expense reimbursement cash receipts. The net effects of the foregoing adjustments for the year ended December 31, 2017 resulted in the balance of the Contingent Reserve being equal to $1,119,671 as of December 31, 2017.

For the year ended December 31, 2016, the Trustee increased the Contingent Reserve by (i) $6,738 and $812 for expense reimbursement cash receipts for the first and third quarters of 2016, respectively, (ii) $101 for a prior period expense refund received from a vendor, and (iii) $107,659 for Royalty income received from BP in September 2016 after the distribution to unitholders had been announced for the month of September 2016, which Royalty income was included in the October 2016 distribution to unitholders. For the year ended December 31, 2016, the Trustee decreased the Contingent Reserve by (i) $101 for prior period expense refund received from a vendor, (ii) $812 for expected expense reimbursement cash receipts, and (iii) $107,659 for Royalty income received from BP in September 2016 after the distribution to unitholders had been announced for the month of September 2016, which Royalty income was included in the October 2016 distribution to unitholders. The net effects of the foregoing adjustments for the year ended December 31, 2016 resulted in the balance of the Contingent Reserve being equal to $1,000,000 as of December 31, 2016.

Liability of Unitholders

In regard 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's 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, the 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

Table of Contents

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

Classification of the Trust

In a technical advice memorandum dated February 26, 1982, the National Office of the Internal Revenue Services (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 such unitholder's pro rata share of the income and expense of the Trust as if such 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 period.

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., 601 Travis Street, Floor 16, Houston, Texas 77002, telephone number 713-483-6020, 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. 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.

The U.S. Tax Cuts and Job Act (the "2017 Tax Act") was enacted on December 22, 2017. The 2017 Tax Act is comprehensive legislation that contains substantial changes to U.S. taxation. The Trust does not expect the new tax law to have any significant impact due to the Trust being classified as a grantor trust for U.S. income tax purposes. However, unitholders should consult with their personal tax advisors to determine how the 2017 Tax Act impacts any items of income or deduction received from the Trust.

This summary is based on current provisions of the Internal Revenue Code of 1986, as amended ("Code"), existing and proposed Internal Revenue Treasury Regulations ("Treasury Regulations") thereunder and current administrative rulings and court decisions, all of which are subject to changes that may or may not be retroactively applied. In addition, the Code and Treasury Regulations are expected to be changed based on the enactment of the 2017 Tax Act. The 2017 Tax Act has not been interpreted by the courts or the IRS. No assurance can be provided that the statements set forth herein

Table of Contents

(which do not bind the IRS or any court) will not be challenged by the IRS or will be sustained by any court if challenged.

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 such units to the extent that this allowance exceeds cost depletion as computed for the applicable 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 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

Individuals, estates, and trusts with income above certain thresholds are subject under Section 1411 of the Code to an additional 3.8% tax also known as the Net Investment Income Tax ("NIIT") on their net investment income. Grantor trusts such as Mesa Royalty Trust are not subject to the NIIT; however, the unitholders may be subject to the tax. For these purposes, investment income would generally include certain income derived from investments, such as the royalty income derived from the units and gain realized by a unitholder from a sale of the units.

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 U.S. Treasury. A non-U.S. unitholder may elect to treat Royalty income as effectively connected with the conduct of a U.S. 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 U.S. 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 U.S. real property holding corporation. Accordingly, a non-U.S. unitholder may be subject to U.S. 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 Royalty income as effectively connected with the conduct of a U.S. 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, and 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 Trust units.

Pursuant to the Foreign Account Tax Compliance Act (commonly referred to as "FATCA"), distributions from the Trust to "foreign financial institutions" and certain other "non-financial foreign entities" may be subject to U.S. withholding taxes. Specifically, certain "withholdable payments" (including certain royalties, interest and other gains or income from U.S. sources) made to a foreign financial institution or non-financial foreign entity will generally be subject to the withholding tax unless the foreign financial institution or non-financial foreign entity complies with certain information reporting, withholding, identification, certification and related requirements imposed by FATCA. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the U.S. governing FATCA may be subject to different rules. Foreign unitholders are encouraged to consult their own tax advisors regarding the possible implications of these withholding provisions on their investment in Trust units.

Tax-Exempt Organizations

The Royalty and interest income should not be "unrelated business taxable income" (as defined in Code § 512(b)), 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.

Table of Contents

DESCRIPTION OF ROYALTY PROPERTIES

Producing Acreage and Wells as of December 31, 2017:

	Producing Acres(1)		Producing Gas Wells(1)	
	Gross	Net	Gross	Net
Hugoton Royalty Properties (Kansas)	99,654	99,413	463	402
San Juan Basin Royalty Properties (Northwestern New Mexico and Southwestern Colorado)	40,716	31,328	2,620	299
Total	140,370	130,741	3,083	701

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

Hugoton Royalty Properties

The principal property interest conveyed to the Trust accounts was carved out of Linn's working interest in 104,437 net producing acres in the Hugoton field of Kansas. The life of the field is expected to extend beyond the year 2042.

The natural 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 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 Royalty Properties

The Trust's interest in the San Juan Basin Royalty Properties was conveyed from PNR's working interest in 31,328 net producing acres in Northwestern New Mexico and Southwestern Colorado. PNR completed the San Juan Basin Sale to ConocoPhillips on April 30, 1991. ConocoPhillips subsequently sold its underlying interest in substantially all of the San Juan Basin Colorado 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 San Juan Basin Colorado Properties to BP. Starting from the date of the San Juan Basin Sale and ending on July 31, 2017, ConocoPhillips operated substantially all of the San Juan Basin New Mexico Properties, except for an immaterial number of properties assigned to XTO effective January 1, 2005. On July 31, 2017, ConocoPhillips sold its San Juan Basin assets to Hilcorp San Juan LP ("Hilcorp"), an affiliate of Hilcorp Energy Company. Substantially all of the natural gas produced from the San Juan Basin is currently being sold on the spot market. See "Description of the Trust".

Drilling

There were no exploratory wells drilled on any Royalty Properties during 2017, 2016, or 2015.

Table of Contents

Reserves

A study of the proved oil and gas reserves covering the Hugoton and San Juan Basin Royalty Properties (the "Reserve Report") and attributable to the Trust has been made by DeGolyer and MacNaughton, independent petroleum engineering consultants, as of December 31, 2017. A copy of this Reserve Report has been filed as Exhibit 99.1 to this Form 10-K. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Astana, Moscow and Algiers. The firm's more than 150 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. 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 President at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the Reserve Report is a Registered Professional 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 degree in Civil Engineering from Texas A&M University in 1979 and he is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

The 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, 2017, of the Trust's ownership in the net overriding royalty interests in the Royalty Properties are presented below. Total liquid reserves (condensate and natural gas liquids) are expressed in thousands of barrels (Mbbl) and gas reserves are expressed in thousands of cubic feet (Mcf).

	BP	Hilcorp	Linn	Total(1)
Proved Developed				
Oil and Condensate	0	8	0	8
Natural Gas Liquids	0	287	73	360
Gas	1,281	3,678	1,351	6,310
Proved Undeveloped				
Oil and Condensate	0	0	0	0
Natural Gas Liquids	0	0	0	0
Gas	0	0	0	0
Total, Proved				
Oil and Condensate	0	8	0	8
Natural Gas Liquids	0	287	73	360
Gas	1,281	3,678	1,351	6,310

(1) Data from Red Willow and XTO was omitted in the Reserve Report, because each operates an immaterial number of wells relative to the total number of wells currently producing from the Royalty Properties. Excess production costs related to Red Willow and XTO as of December 31, 2017 and 2016 are included in Net Proceeds paid to the Trust by Red Willow and XTO.

Table of Contents

The estimated future net revenue and standardized measure of future net royalty income, discounted at 10 percent per annum attributable to the Trust's Royalty as of December 31, 2017 is summarized in the table below. These estimates are provided based upon the economic assumptions furnished by the Working Interest Owners, and are expressed in thousands of dollars:

	BP	Hilcorp	Linn	Total
Future Royalty income(1)	$ 1,754	$ 15,577	$ 6,600	$ 23,931

	BP	Hilcorp	Linn	Total
Standardized Measure of Future Net Royalty Income, discounted at 10% per annum(1)	$ 1,067	$ 8,119	$ 4,160	$ 13,346

(1) Future income tax expenses were excluded in the preparation of these estimates.

Please read "Summary Reserve Report from DeGolyer and MacNaughton" attached hereto as Exhibit 99.1 for more information.

The Reserve Report was delivered to the Trustee on March 19, 2018. 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 of the Working Interest Owners 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 $35.91 per barrel ("Bbl"); (2) natural gas liquids prices $17.25 per Bbl for the San Juan Basin Royalty Properties and $22.85 per Bbl for Hugoton Royalty Properties; and (3) natural gas prices $2.81 per Mcf for San Juan Basin Royalty Properties and $3.65 per Mcf for Hugoton Royalty 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 Royalty 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 1, 2 and 7, respectively, in the Notes to Financial Statements contained in Item 8 of this Form 10-K.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures, including many factors beyond the control of the producer. Reserve data included above and in these reports represent estimates only and should not be construed as being exact. The discounted present values shown by the Reserve Report 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 ("FASB"). Accordingly, the estimates are based on existing economic and operating conditions in effect at December 31, 2017, 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 reserve reports are limited to proved reserves, future capital expenditures for recovery of reserves not classified as proved

Table of Contents

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 estimates 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

Sales and production data from the Royalty Properties for the last three fiscal years is included in the table below. For additional information related to our Reserve Report, see "Note 7 Supplemental Reserve Information" under Item 8 of this Form 10-K.

	Hugoton			**San Juan Basin New Mexico(4)**			**San Juan Basin Colorado**			**Total**		
	Natural Gas	**Natural Gas Liquids**	**Oil and Condensate**	**Natural Gas**	**Natural Gas Liquids**	**Oil and Condensate**	**Natural Gas**	**Natural Gas Liquids**	**Oil and Condensate**	**Natural Gas**	**Natural Gas Liquids**	**Oil and Condensate**
Year ended December 31, 2017:												
Average Sales Price	$ 3.66	$ 22.87	$	$ 2.20	$ 16.17	$ 37.91	$ 1.61	$	$	$ 2.36	$ 19.24	$ 37.91
Average Production Costs(1)	$ 2.03	$ 12.99	$	$ 1.80	$ 13.10	$ 31.56	$ 0.39	$	$	$ 1.31	$ 13.05	$ 31.56
Net production volumes attributable to the	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)
Royalty paid(2)	262,789	15,921		341,305	18,771	774	383,409			987,503	34,692	774
Year ended December 31, 2016:												
Average Sales Price	$ 2.86	$ 11.38	$	$ 1.64	$ 12.40	$ 31.25	$ 1.21	$	$	$ 1.74	$ 12.00	$ 31.25
Average Production Costs(1)	$ 5.98	$ 22.02	$	$ 2.27	$ 17.28	$ 39.58	$ 1.36	$	$	$ 2.70	$ 19.12	$ 39.58
Net production volumes attributable to the	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)
Royalty paid(2)(3)	121,662	9,608		267,253	15,142	829	210,532			599,447	24,750	829
Year ended December 31, 2015:												
Average Sales Price	$ 3.47	$ 13.83	$	$ 2.24	$ 13.30	$ 39.81	$ 1.84	$	$	$ 2.67	$ 13.51	$ 39.81

Average Production Costs(1)	$ 3.54	$ 15.31	$	$ 2.29	$ 13.90	$ 39.75	$ 65.45	$	$	$ 3.81	$ 14.45	$ 39.75
Net production volumes attributable to the	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Mcf)	(Bbls)	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)
Royalty paid(2)	199,976	15,080		352,323	23,657	932	9,556			561,855	38,737	932

(1) 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. 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.

(2) Net production volumes attributable to the Royalty are determined by dividing Royalty income by the average sales price received. Any differences noted are due to rounding.

(3) In order to more closely align the reporting and payment of Royalty income from the San Juan Basin Colorado Properties operated by BP, the Trustee elected to report BP's production from December 2016 for the year ended December 31, 2016. Historically, BP's December production month has correlated to the Trust's January accounting month. However, such election did not impact Royalty income or cash in the Trust's financial statements for the year ended December 31, 2016, because the San Juan Basin Colorado Properties operated by BP generated excess production costs of $3,860 during the December 2016 production month and no payment was due to the Trust by BP. The effect of the Trustee's election to include the December 2016 production month for the year ended December 31, 2016 is as follows: (i) the Summary of Royalty Income, Production, Prices and Costs include the Trust's proportionate share of gross proceeds of $68,327, the Trust's proportionate share of operating costs of $72,187, and net production volumes attributable to the Royalty paid of 40,163 Mcf, and (ii) $3,860 of excess production costs related to the San Juan Basin Colorado Properties operated by BP as of December 31, 2016 were included in the Excess Production Costs footnote to the Trust's financial statements for the year ended December 31, 2016.

Table of Contents

(4) Effective September 2017, following Hilcorp's acquisition of ConocoPhillips interests in the San Juan New Mexico Properties, Hilcorp continued to make an estimated payment of Net Proceeds to the Trust each month consistent with the monthly amount previously paid by ConocoPhillips. These estimated payments remain subject to reconciliation with respect to actual revenue, costs and net proceeds and the effects of pricing during the prior months after Hilcorp has completed its transition as owner of the San Juan New Mexico Properties. The reconciliation and true-up of the estimated payments for this transition period may affect the Trust's future receipt of Net Proceeds from Hilcorp.

CONTRACTS

Hugoton Royalty Properties

Natural gas and natural gas liquids produced by Linn from the Hugoton Royalty Properties accounted for approximately 44% of the Royalty income of the Trust for the year ended December 31, 2017. Linn 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. Linn has advised the Trust that it expects to continue to market natural gas production from the Hugoton field under short-term and multi-month contracts. Overall average daily market prices received for natural gas from Hugoton Royalty Properties were higher for the year ended December 31, 2017 as compared to the year ended December 31, 2016.

In June 1994, PNR entered into a Gas Transportation Agreement ("Gas Transportation Agreement") with Western Resources, Inc. ("WRI") for a primary term of five years, commencing June 1, 1995. Thereafter, this contract has renewed on a year to year basis. WRI subsequently assigned its rights and obligations under the Gas Transportation Agreement to Oneok Field Services ("Oneok"), and PNR subsequently assigned its rights and obligations under the Gas Transportation Agreement to Linn. In their termination notice issued May 12, 2015, Oneok noted they were agreeable to negotiating a new agreement in order to continue to provide gathering and compression service. On January 1, 2016, an affiliate of Linn acquired the gathering line from Oneok and a new gas compression agreement was entered into. However, Oneok continued to provide compression services under such new gas compression agreement from January 1, 2016 through December 31, 2016 at a rate of $0.13 per Mcf, and Linn provided other services under the new gas compression agreement at a rate of $0.06 per Mcf. In connection with Linn's reorganization and bankruptcy proceedings, Linn rejected the Oneok gas compression agreement under applicable bankruptcy laws, and thereafter, Oneok ceased to provide any services for the Hugoton Royalty Properties. An affiliate of Linn began providing services similar to those set forth in the Oneok gas compression agreement effective January 1, 2017, and began charging the Royalty from the Hugoton Royalty Properties at a rate of $0.1569 per Mcf. For the entirety of the year ended December 31, 2017 and as of the date of this Form 10-K, Linn has provided and continues to provide services pursuant to the new agreement.

San Juan Basin

Natural gas, oil, condensate and natural gas liquids produced from the San Juan Basin Royalty Properties accounted for approximately 56% of the Royalty income of the Trust for the year ended December 31, 2017. The majority of the natural gas produced from the San Juan Basin Royalty Properties 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 realized for natural gas produced from the Royalty Properties and the quantities of gas sold. According to the U.S. Energy Information Administration of the Department of Energy, the Henry Hub Natural Gas Spot Prices were $2.50 per MMBtu in 2016 and increased to $2.99 per MMBtu in 2017. 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 those periods. Because of the time lag between the date

Table of Contents

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. Henry Hub Natural Gas Spot Prices are quoted in MMBtu, a commonly used energy measurement that has a conversion formula defined and published by the SEC for the purpose of estimating price per Mcf in the Reserve Report.

Competition

The production and sale of gas from the Royalty Properties are 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. 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. Linn 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 plants. 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 few 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 pipelines, but does not regulate natural gas gathering facilities. 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 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 at any time 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

Each of the jurisdictions encompassing the Royalty Properties has statutory provisions regulating the production and sale of crude oil and natural gas. The regulations often require permits for the drilling of wells and may specify rules related to the spacing of wells, the prevention of waste of oil and gas resources, the rate of production, the prevention and clean-up of pollution, and other matters.

Table of Contents

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take and common purchaser requirements, as well as complaint-based rate regulation. For example, Oklahoma, Kansas and Texas prohibit discriminatory gathering rates, but Colorado and New Mexico do not.

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*, onshore gathering of gas (i) through a pipeline that operates at less than 0 psig; (ii) through a pipeline that is not a regulated onshore gathering line (as determined in 49 C.F.R. § 192.8); and (iii) within the inlets of the Gulf of Mexico, except for the requirements in 49 C.F.R. § 192.1(b). The Royalty Properties are located in the Hugoton field of Kansas and the San Juan Basin of New Mexico and Colorado. Each of Colorado, Kansas and New Mexico has 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 applicable law 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 and release 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 and released 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 discharged and 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 certain material laws, rules and regulations to which the operations of the Royalty Properties may be subject.

Hazardous Substances. The Comprehensive Environmental Response, Compensation and Liability Act, referred to as "CERCLA" or the Superfund law, and comparable state laws impose liability, 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 Royalty Properties 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 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 regardless of whether or not such Working Interest Owner directly or indirectly caused the unpermitted discharge or release.

In addition, in the course of the Working Interest Owners' 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 ("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 Environmental Protection Agency (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 (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 (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. The 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, 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.

Table of Contents

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 the 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, hydraulic fracturing requires large amounts of water. This water, along with any produced water, is often sent to injection wells for disposal. This activity has been associated with earthquakes and some states, particularly Oklahoma, have limited injection well activity. If states in which the Working Interest Owners' operate adopt limitations, it could have a negative impact on production.

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. The 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. The EPA has promulgated certain regulations that require new and modified stationary source of greenhouse gases above certain thresholds to report, limit or control such emissions, including rules to control methane 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. Recently, EPA proposed rules to stay certain portions of the rules promulgated to control greenhouse gas emission related to oil and gas production. 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.

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.

Table of Contents

Item 1A. Risk Factors.

Although risk factors are described elsewhere in this Form 10-K together with the Disclosures Regarding Forward-Looking Statements, the following is a summary of the principal risks associated with an investment in the Trust's units.

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, since the second half of 2014 have declined substantially from historic highs and may remain depressed for the foreseeable future. In 2017, crude oil prices per Bbl ranged from a high of approximately $60.46 to a low of approximately $42.48. The NYMEX crude oil spot prices per Bbl were $60.46 and $53.75 as of December 31, 2017 and 2016 respectively. 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 in 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.

Any additional decreases in prices of natural gas may materially and adversely affect our cash generated from operations, results of operations and reduce net proceeds available to the Trust and distributions to Trust unitholders.

During the eight years prior to December 31, 2017, Henry Hub natural gas prices have ranged from a high of $8.15 per MMBtu in 2014 to a low of $1.49 per MMBtu in 2016. On December 31, 2017, the Henry Hub Natural Gas Spot Price was $3.69 per MMBtu. The reduction in prices has been caused by many factors, including increases in natural gas production and reserves from unconventional

19

(shale) reservoirs, without an offsetting increase in demand. The expected increase in natural gas production could cause the prices for natural gas to remain at current levels or fall to lower levels. If prices for natural gas continue to remain depressed for lengthy periods, we may be required to write down the value of our oil and gas properties. In addition, sustained low prices for gas will negatively impact the value of our estimated reserves and reduce net proceeds and the amount of cash we would otherwise have available to pay cash distributions to unitholders.

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 has established 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. In 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 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.

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, and damage to productive formations or equipment and environmental damages. Any uninsured costs would be deducted as a production cost in calculating net proceeds payable to the Trust.

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

Further, the present value of future net cash flows from proved reserves may not be the current market value of estimated natural gas and oil reserves attributable to the Royalty. In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on the 12-month average oil and gas index prices, calculated as the un-weighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the 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

Table of Contents

developing the underlying properties rely could be a direct target or an indirect casualty of an act of terror.

The Working Interest Owners 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 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 Regulation and Prices Environmental Matters" under Item 1 of this Form 10-K for more information on the environmental laws and government regulations that may be applicable to the Working Interest Owners' operations.

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

Table of Contents

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 coverage. The 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 DeGolyer 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.

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

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 and emission reduction. 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 Regulation and Prices Environmental Matters" under Item 1 of this Form 10-K 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.

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. Some states have adopted and others are considering legislation to restrict hydraulic

Table of Contents

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. In addition, hydraulic fracturing requires large amounts of water. This water, along with any produced water, is often sent to injection wells for disposal. This activity has been associated with earthquakes and some states, particularly Oklahoma, have limited injection well activity. 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 the Working Interest Owners, who are independent from the Trust. 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 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 and estimates, 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 and estimates 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 the 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

Table of Contents

on experts and limited access to information may be viewed as a weakness as compared to the management and oversight of entity forms other than trusts.

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

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

The 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. 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 any

Table of Contents

of the Working Interest Owners. Unlike corporations which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a corporate Trustee in accordance with the Trust Indenture and other organizational documents. The Trustee has extremely limited discretion in its administration of the Trust.

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

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

The limited liability of the Trust unitholders is uncertain.

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

The future financial condition of Working Interest Owners or other operators of the underlying properties could impede the operation of wells.

The value of the Royalty and the Trust's ultimate cash available for distribution is highly dependent on the financial condition of the operators of the wells. The ability to operate the underlying properties depends on all operators' current and future financial condition and economic performance and access to capital, which in turn will depend upon the supply and demand for oil and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond the control of such operators.

In the event of the bankruptcy of any operator of the underlying properties, the Working Interest Owners in the affected properties, creditors or the debtor-in-possession may have to seek a new party to perform the operations of the affected wells. The creditors or debtor-in-possession may not be able to find a replacement operator, and they may not be able to enter into a new agreement with such replacement party on favorable terms or within a reasonable period of time.

Financial information of the Trust is not prepared in accordance with U.S. GAAP.

The financial statements of the Trust are prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles ("*U.S. GAAP*"). Although this basis of accounting is permitted for royalty trusts by the SEC, the financial statements of the Trust differ from U.S. GAAP financial statements, because net profits income is not accrued in the month of production, expenses are not recognized when incurred, and cash reserves may be established for certain contingencies that would not be recorded in U.S. GAAP financial statements.

Table of Contents

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

The Trust owns property interests in the Hugoton field of Kansas and the San Juan Basin of 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 the Working Interest Owners that it may be 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 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 are made against Royalty income, such charges could have a material impact on future Royalty income.

Item 4. Mine Safety Disclosures.

Not applicable.

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 years ended December 31 were as follows:

	2017			2016		
Quarter	**High**	**Low**	**Distribution**	**High**	**Low**	**Distribution**
First	$ 14.40	$ 9.70	$ 0.4236	$ 9.19	$ 5.64	$ 0.0802
Second	$ 16.70	$ 11.25	$ 0.3778	$ 11.18	$ 7.54	$ 0.0783
Third	$ 16.20	$ 11.50	$ 0.3450	$ 11.02	$ 8.12	$ 0.1651
Fourth	$ 18.50	$ 14.30	$ 0.3659	$ 12.85	$ 8.25	$ 0.3242

At March 30, 2018, the 1,863,590 units outstanding were held by 551 unitholders of record.

Item 6. Selected Financial Data.

Not applicable.

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

Trust Overview

The following review of Mesa Royalty Trust's (the "Trust") 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 Basin Royalty Properties (as each is defined below) 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. Any discussion of "actual" production volumes represents the hydrocarbons that were produced from the properties in which the Trust has an overriding royalty interest.

The Trust was created on November 1, 1979, and is now governed by the Mesa Royalty Trust Indenture (as amended, the "Trust Indenture"). Through a series of conveyances, assignments, and acquisitions, the Trust currently owns an overriding royalty interest (the "Royalty") equal to 11.44% of 90% of the Net Proceeds (as defined and described in an Overriding Royalty Conveyance, dated as of November 1, 1979 (the "Conveyance")) attributable to the specified interest in certain producing oil and gas properties located in the:

- Hugoton field of Kansas (the "Hugoton Royalty Properties");

- San Juan Basin field of New Mexico (the "San Juan Basin New Mexico Properties");

- San Juan Basin field of Colorado (the "San Juan Basin Colorado Properties", and together with the "San Juan Basin New Mexico Properties, the "San Juan Basin Royalty Properties", and together with the Hugoton Royalty Properties and the San Juan Basin Royalty Properties, the "Royalty Properties").

Pursuant to past conveyances and bankruptcy proceedings, Linn Energy, Inc. ("Linn"), Hilcorp San Juan LP ("Hilcorp"), XTO Energy, Inc. ("XTO"), BP Amoco Company ("BP"), and Red Willow Production Company ("Red Willow") are the operators of certain portions of the Hugoton Royalty Properties and San Juan Basin Royalty Properties (each of Linn, Hilcorp, XTO, BP, and Red Willow being a "Working Interest Owner", and together, the "Working Interest Owners"). As used in this report, Linn refers to the current operator of the Hugoton Royalty Properties, Hilcorp refers to the current operator of the San Juan Basin New Mexico Properties, and BP and Red Willow refer to the currents co-operators of certain tracts of land included in the San Juan Basin Colorado Properties, unless otherwise indicated.

The Trust is a passive entity whose purposes are limited to: (1) converting the Royalties to cash, either by retaining them and collecting the proceeds of production (until production has ceased or the Royalties are otherwise terminated) or by selling or otherwise disposing of the Royalties; and (2) distributing such cash, net of amounts for payments of liabilities to the Trust, to the unitholders. The Trust has no sources of liquidity or capital resources other than the revenues, if any, attributable to the Royalties and interest on cash held by the Trustee as a reserve for liabilities or for distribution. The Trust does not undertake or control any capital projects or make capital expenditures. While the Trust's Royalty income is net of capital expenditures, these capital expenditures are controlled and paid by the Working Interests Owners, and the Trust receives Royalty income net of these expenses. In addition, the Trust does not have any off-balance sheet arrangements or other contingent obligations.

Liquidity and Capital Resources

Liquidity. As discussed in "Business Description of the Trust" under Item 1 of this Form 10-K, the Trust's primary source of cash is the Royalty income received from its share of the net proceeds from the Royalty Properties, and the only other source of cash is interest income earned pursuant to the Trust Indenture. For estimates of future Royalty income attributable to the Royalty, refer to the Notes to Financial Statements under Item 8 of this Form 10-K.

In addition, the Working Interest Owners reimburse the Trust each quarter for certain expenses incurred by the Trust on their behalf. As of December 31, 2017 and 2016, there were $0 and $0 of unreimbursed expenses, respectively. In accordance with the provisions of the Conveyance, generally all revenues received by the Trust, net of unreimbursed Trust administrative expenses and sums paid to or from any reserves established pursuant to the Trust Indenture, are distributed to the unitholders. The terms of the Trust Indenture provide, among other things, that the Trustee may establish cash reserves and borrow funds to pay liabilities of the Trust, and may pledge assets of the Trust to secure payment

Table of Contents

of the borrowings. During 2011, the Trustee withheld $1.0 million to establish a reserve for future unknown contingent liabilities and expenses (the "Contingent Reserve") in accordance with the Trust Indenture. At any given time, the balance of the Contingent Reserve is included in cash and short-term investments.

For the year ended December 31, 2017, the Trustee increased the Contingent Reserve by (i) $82,244 of Royalty income received from BP in March 2017 after the distribution to unitholders had been announced for the month of March 2017, which Royalty income was included in the April 2017 distribution to unitholders, (ii) $47,840 of Royalty income received from BP in June 2017 after the distribution to unitholders had been announced for the month of June 2017, which Royalty income was included in the July 2017 distribution to unitholders, (iii) $1,307 for the amount of September expected expense reimbursement cash receipts, received in October 2017, (iv) $49,211 of Royalty income received from BP in December 2017 after the distribution to unitholders had been announced for the month of December 2017, which Royalty income was included in the January 2018 distribution to unitholders, and (v) $70,460 of December 2017 expenses that was included in the distribution calculation for December 2017, but not paid by the Trust until January 2018. For the year ended December 31, 2017, the Trustee decreased the Contingent Reserve by (i) $82,244 and $47,840 of aggregate Royalty income received from BP in March 2017 and June 2017, respectively, and (ii) $1,307 for expected expense reimbursement cash receipts. The net effects of the foregoing adjustments for the year ended December 31, 2017 resulted in the balance of the Contingent Reserve being equal to $1,119,671 as of December 31, 2017. See "Financial Review Unreimbursed Expenses and the Contingent Reserve" for complete information about adjustments to the Contingent Reserve for the year ended December 31, 2016.

Capital Resources. The Trust is a passive entity that does not undertake or control any capital projects or make capital expenditures. While the Trust's Royalty income is net of capital expenditures, these capital expenditures are controlled and paid by the Working Interests Owners, and the Trust receives Royalty income net of these expenses. Therefore, the Trust has no material commitments for capital expenditures.

Table of Contents

Years Ended December 31, 2017 and 2016

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

	Hugoton			**San Juan Basin New Mexico(6)**			**San Juan Basin Colorado**			**Total**		
	Natural Gas	**Natural Gas Liquids**	**Oil and Condensate**	**Natural Gas**	**Natural Gas Liquids**	**Oil and Condensate**	**Natural Gas**	**Natural Gas Liquids**	**Oil and Condensate**	**Natural Gas**	**Natural Gas Liquids**	**Oil and Condensate**
Year ended December 31, 2017:												
The Trust's proportionate share of Gross Proceeds(1)	$ 1,494,502	$ 570,952	$	$ 1,364,797	$ 548,582	$ 53,737	$ 766,538	$	$	$ 3,625,837	$ 1,119,534	$ 53,737
Less the Trust's proportionate share of Capital costs	(5,901)	(2,020)		(7,480)	(3,001)	(297)				(13,381)	(5,021)	(297)
Operating costs	(526,661)	(204,860)		(606,668)	(242,953)	(24,116)	(148,391)			(1,281,720)	(447,813)	(24,116)
Net Proceeds(2)	$ 961,940	$ 364,072	$	$ 750,649	$ 302,628	$ 29,324	$ 618,147	$	$	$ 2,330,736	$ 666,700	$ 29,324
Royalty Income(2)	$ 961,940	$ 364,072	$	$ 752,253	$ 303,505	$ 29,324	$ 617,699	$	$	$ 2,331,892	$ 667,577	$ 29,324
Average Sales Price	$ 3.66	$ 22.87	$	$ 2.20	$ 16.17	$ 37.91	$ 1.61	$	$	$ 2.36	$ 19.24	$ 37.91
Average Production Costs(3)	$ 2.03	$ 12.99	$	$ 1.80	$ 13.10	$ 31.56	$ 0.39	$	$	$ 1.31	$ 13.05	$ 31.56
Net production volumes attributable to the	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)
Royalty paid(4)	262,789	15,921		341,305	18,771	774	383,409			987,503	34,692	774
Year ended December 31, 2016:												
The Trust's proportionate share of Gross Proceeds(1)	$ 1,075,599	$ 320,953	$	$ 1,043,817	$ 448,571	$ 58,580	$ 602,653	$	$	$ 2,722,069	$ 769,524	$ 58,580
Less the Trust's proportionate share of Capital costs	(6,422)	(1,618)		(27,157)	(10,673)	(1,231)				(33,579)	(12,291)	(1,231)
Operating costs	(721,225)	(209,992)		(579,744)	(250,971)	(31,568)	(286,173)			(1,587,142)	(460,963)	(31,568)
Net Proceeds(2)	$ 347,952	$ 109,343	$	$ 436,916	$ 186,927	$ 25,781	$ 316,480	$	$	$ 1,101,348	$ 296,270	$ 25,781

Royalty Income(2)	$ 347,952	$ 109,343	$	$ 438,460	$ 187,754	$ 25,894	$ 255,388	$	$	$ 1,041,800	$ 297,097	$ 25,894
Average Sales Price	$ 2.86	$ 11.38	$	$ 1.64	$ 12.40	$ 31.25	$ 1.21	$	$	$ 1.74	$ 12.00	$ 31.25
Average Production Costs(3)	$ 5.98	$ 22.02	$	$ 2.27	$ 17.28	$ 39.58	$ 1.36	$	$	$ 2.70	$ 19.12	$ 39.58
Net production volumes attributable to the	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)	(Mcf)	(Bbls)	(Bbls)
Royalty paid(4)(5)	121,662	9,608		267,253	15,142	829	210,532			599,447	24,750	829

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

(2) Royalty income is computed after deducting the Trust's proportionate share of capital costs, operating costs and interest on any cost carryforward from the Trust's proportionate share of Gross Proceeds. As a result of excess production costs incurred in one monthly operating period and then recovered in a subsequent monthly operating period, the Royalty income paid to the Trust may not agree to the Trust's royalty interest in the Net Proceeds (as defined in the Conveyance). The excess production costs must be recovered by the Working Interest Owners before any distribution of Royalty income will be made to the Trust.

San Juan Basin New Mexico Properties. Excess production costs in the amount of $6,070 and $3,591 as of December 31, 2017 and 2016, respectively, were related to the San Juan Basin New Mexico Properties operated by XTO. Excess production costs related to the San Juan Basin New Mexico Properties operated by XTO were approximately $2,479 and $2,484 for year ended December 31, 2017 and 2016, respectively.

San Juan Basin Colorado Properties. Excess production costs related to the San Juan Basin Colorado Properties operated by BP and Red Willow were approximately $0 and $15,944, respectively, as of December 31, 2017, and $3,860 and $12,532, respectively, as of December 31, 2016. Excess production costs related to the San Juan Basin Colorado Properties operated by BP and Red Willow were approximately $0 and $3,412, respectively, for the year ended December 31, 2017, and $3,860 and $7,384, respectively, for the year ended December 31, 2016. The Trust recovered prior period excess production costs related to the San Juan Basin Colorado Properties operated by BP of $3,860 and $72,336 during the years ended December 31, 2017 and 2016, respectively.

(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. Any differences noted are due to rounding.

(5) In order to more closely align the reporting and payment of Royalty income from the San Juan Basin Colorado Properties operated by BP, the Trustee elected to report BP's production from December 2016 for the year ended December 31, 2016. Historically, BP's December production month has correlated to the Trust's January accounting month. However, such election did not impact Royalty income or cash in the Trust's financial statements for the year ended December 31, 2016, because the San Juan Basin Colorado Properties operated by BP generated excess production costs of $3,860 during the December 2016 production month and no payment was due to the Trust by BP. The effect of the Trustee's election to include the December 2016 production month for the year ended December 31, 2016 is as follows: (i) the Summary of Royalty Income, Production, Prices and Costs include the Trust's proportionate share of gross proceeds of $68,327, the Trust's proportionate share of operating costs of $72,187, and net production volumes attributable to the Royalty paid on 40,163 thousand cubic feet ("Mcf") of natural gas, and (ii) $3,860 of excess production costs related to the San Juan Basin Colorado Properties operated by BP as of December 31, 2016 were included in the Excess Production Costs footnote to the Trust's financial statements for the year ended December 31, 2016.

Table of Contents

(6) Effective September 2017, following Hilcorp's acquisition of Conoco, Inc.'s ("ConocoPhillips") interests in the San Juan New Mexico Properties, Hilcorp continued to make an estimated payment of Net Proceeds to the Trust each month consistent with the monthly amount previously paid by ConocoPhillips. These estimated payments remain subject to reconciliation with respect to actual revenue, costs and net proceeds and the effects of pricing during the prior months after Hilcorp has completed its transition as owner of the San Juan New Mexico Properties. The reconciliation and true-up of the estimated payments for this transition period may affect the Trust's future receipt of Net Proceeds from Hilcorp.

Financial Review

	2017	2016
Royalty income	$ 3,028,793	$ 1,364,791
Interest income	10,221	1,899
General and administrative expenses	(100,795)	(152,778)
Distributable income	$ 2,938,219	$ 1,213,912
Distributable income per unit	$ 1.5766	$ 0.6514

Royalty and Interest Income. The Trust's Royalty income was $3,028,793 and $1,364,791 for the years ended December 31, 2017 and 2016, respectively. The increase for the year ended December 31, 2017 as compared to December 31, 2016 was primarily a result of higher natural gas, natural gas liquids and oil and condensate prices, reduced capital expenditures and operating costs, and increased net natural gas and natural gas liquids production volumes for the year ended December 31, 2017. The Trust's Interest income for the years ended December 31, 2017 and 2016 was $10,221 and $1,899, respectively. In accordance with the Trust Indenture and as explained below, interest on cash on hand was paid at a rate equivalent to 1.5% below the prime interest rate.

General and Administrative Expense. General and administrative expense was $100,795 and $152,778 for the years ended December 31, 2017 and 2016, respectively. The Trustee's fees are included in general and administrative expense. The decrease for the year ended December 31, 2017 as compared to December 31, 2016 was primarily a result of general and administrative expenses in the amount of $70,460 for December 2017 being paid by the Trust in January 2018. If the Trust had paid such expenses in December 2017, general and administrative expenses for the year ended December 31, 2017 would have been $171,255.

For the year ended December 31, 2017, the Trustee was due $475,000 for its services. The Trust paid $433,152 of this amount to the Trustee, and $41,848 was allocated to offset against interest due to the Trust under the Trust Indenture. The Trust Indenture requires that cash being held by the Trustee earn interest at 1.5% below the prime rate, which would have yielded the Trust a 2.25% annualized return from January 1, 2017 through March 15, 2017, a 2.50% annualized return from March 16, 2017 to June 14, 2017, a 2.75% annualized return from June 15, 2017 through December 13, 2017, and a 3.00% annualized return from December 14, 2017 through December 31, 2017. However, due to the current interest rate environment, the Trustee was unable to obtain an account in which such an interest rate was available. In the event such an interest rate is unavailable in the future, the Trustee intends to allocate certain of its fees due to the Trust to meet the minimum interest rate payable under the Trust Indenture. In future periods the Trustee will continue to allocate a portion of the fees earned for its services to the Trust until the remaining $15,365 of interest due to the Trust is fully offset.

Unreimbursed Expenses and the Contingent Reserve. The Working Interest Owners partially reimburse the Trust each quarter for amounts paid in connection with the Trustee's services. For the year ended December 31, 2017, the Trustee's aggregate fees were $433,152 and the Working Interest Owners reimbursed the aggregate sum of $383,588 to the Trustee. For the year ended December 31, 2016, the Trustee's aggregate fees were $433,152 and the Working Interest Owners reimbursed the aggregate sum of $383,588 to the Trustee. As of the years ended December 31, 2017 and 2016, the Trust incurred unreimbursed expenses of $0 and $0, respectively.

Table of Contents

During 2011, the Trustee, acting pursuant to the Trust Indenture, withheld $1.0 million to establish the Contingent Reserve, with such amount being included in cash and short-term investments. The Trustee reserves the right to determine whether or not to release cash reserves in future periods with respect to any reimbursement expenses. For the year ended December 31, 2017, the Trustee increased the Contingent Reserve by (i) $82,244 of Royalty income received from BP in March 2017 after the distribution to unitholders had been announced for the month of March 2017, which Royalty income was included in the April 2017 distribution to unitholders, (ii) $47,840 of Royalty income received from BP in June 2017 after the distribution to unitholders had been announced for the month of June 2017, which Royalty income was included in the July 2017 distribution to unitholders, (iii) $1,307 for the amount of September expected expense reimbursement cash receipts, received in October 2017, (iv) $49,211 of Royalty income received from BP in December 2017 after the distribution to unitholders had been announced for the month of December 2017, which Royalty income was included in the January 2018 distribution to unitholders, and (v) $70,460 of December 2017 expenses that was included in the distribution calculation for December 2017, but not paid by the Trust until January 2018. For the year ended December 31, 2017, the Trustee decreased the Contingent Reserve by (i) $82,244 and $47,840 of aggregate Royalty income received from BP in March 2017 and June 2017, respectively, and (ii) $1,307 for expected expense reimbursement cash receipts. The net effects of the foregoing adjustments for the year ended December 31, 2017 resulted in the balance of the Contingent Reserve, which is included in cash and short-term investments, being equal to $1,119,671 as of December 31, 2017.

For the year ended December 31, 2016, the Trustee increased the Contingent Reserve by (i) the amounts received during the first quarter and third quarter of 2016 related to expense reimbursement cash receipts for previous periods totaling $6,738 and $812, respectively, (ii) a prior period expense refund received from a vendor in the amount of $101 and (iii) $107,659 of royalty income received from BP in September 2016 after the distribution to unitholders had been announced for the month of September 2016, which Royalty income was included in the October 2016 distribution to unitholders. For the twelve months ended December 31, 2016, the Trustee decreased the reserve for future unknown contingent liabilities and expenses for (i) a prior period expense refund received from a vendor in the amount of $101, (ii) the amount of expected expense reimbursement cash receipts of $812 and (iii) $107,659 of Royalty income received from BP in September 2016 after the distribution to unitholders had been announced for the month of September 2016, which Royalty income was included in the October 2016 distribution to unitholders. The net effects of the foregoing adjustments for the year ended December 31, 2016 resulted in the balance of the Contingent Reserve being equal to $1,000,000 as of December 31, 2016.

Distributable Income Available for Distribution. The portion of the Trust's distributable income available for distribution each year includes the Royalty income received from the Working Interest Owners during such period, plus interest income earned to the date of distribution (if any) and increases or withdrawals to and from the Contingent Reserve (if any). Distributable income available for distribution for the years ended December 31, 2017 and 2016 was $2,818,548 and $1,207,174, respectively. For the years ended December 31, 2017 and 2016, the Trust calculated total aggregate distributions of $1.5124 and $0.6478 per unit, respectively.

Operational Review

Hugoton Royalty Properties

Natural gas and natural gas liquids production attributable to the Hugoton Royalty Properties accounted for approximately 44% of the Royalty income of the Trust during the year ended December 31, 2017.

Table of Contents

Royalty Income. Royalty income attributable to the Hugoton Royalty Properties for the years ended December 31, 2017 and 2016 was $1,326,012 and $457,295, respectively. The increase of approximately 190% for the year ended December 31, 2017 as compared to December 31, 2016 was primarily due to higher natural gas and natural gas liquids prices, increased net natural gas and natural gas liquids production volumes and lower operating costs from the Hugoton Royalty Properties in fiscal year 2017.

Operating Costs and Capital Expenditures. Operating costs attributable to the Hugoton Royalty Properties for the years ended December 31, 2017 and 2016 were $731,521 and $931,217, respectively. Linn has informed the Trust that the approximately 21% decrease for the year ended December 31, 2017 as compared to December 31, 2016 was primarily due to actual ad valorem taxes paid and a decrease in the reserve amount, partially offset by an increase in severance taxes which is in line with higher production. Capital expenditures attributable to the Hugoton Royalty Properties for the years ended December 31, 2017 and 2016 were $7,921 and $8,040, respectively.

	2017			2016		
	Natural Gas	**Natural Gas Liquids**	**Oil and Condensate**	**Natural Gas**	**Natural Gas Liquids**	**Oil and Condensate**
Average sales price	$ 3.66	$ 22.87		$ 2.86	$ 11.38	
	(Mcf)	**(Bbls)**	**(Bbls)**	**(Mcf)**	**(Bbls)**	**(Bbls)**
Actual production volumes attributable to the Royalty paid for Hugoton Royalty Properties	408,492	24,982		376,689	28,207	
Net production volumes attributable to the Royalty paid for Hugoton Royalty Properties	262,789	15,921		121,662	9,608	

Average Sales Prices. Average sales prices per Mcf of natural gas and barrel ("Bbl") for natural gas liquids for the Hugoton Royalty Properties is directly dependent on the prices Linn realizes for natural gas sold under short-term and multi-month contracts at market clearing prices to multiple purchasers.

Linn Energy Reorganization. On May 11, 2016, Linn Energy, LLC ("Old Linn"), LinnCo, LLC ("LinnCo"), an affiliate of Old Linn, and certain of Old Linn's direct and indirect subsidiaries (collectively with Old Linn and LinnCo, the "Debtors"), filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Court"). The Debtors' Chapter 11 cases were administered jointly under the caption *In re Linn Energy, LLC, et al.*, Case No. 16-60040.

On January 27, 2017, the Court entered the *Order Confirming (I) Amended Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and its Debtor Affiliates Other Than Linn Acquisition Company, LLC and Berry Petroleum Company, LLC and (II) Amended Joint Chapter 11 Plan of Reorganization of Linn Acquisition Company, LLC and Berry Petroleum Company, LLC*, which approved and confirmed the Amended Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and Its Debtor Affiliates Other Than Linn Acquisition Company, LLC and Berry Petroleum Company, LLC (the "Plan"). The Plan became effective on February 28, 2017 (the "Effective Date").

Pursuant to the Plan, on the Effective Date, all assets of Old Linn (other than equity interests in Linn Acquisition Company, LLC and Berry Petroleum Company, LLC) were conveyed to Linn Energy, Inc. (or a subsidiary thereof), and LinnCo, LLC and Linn Energy, LLC were wound down and

Table of Contents

liquidated. Subsequent to the effectiveness of the Plan, Linn Energy, Inc. is now the reorganized successor to Old Linn. Under the Plan Supplement, as amended, filed with the Court, the Debtors assumed all executory contracts and unexpired leases with the Trust and Mesa Operating Limited Partnership as the counterparty. Furthermore, pursuant to the Plan, the interests in the Hugoton Royalty Properties owned by the Trust shall be preserved and remain in full force and effect in accordance with the terms of the granting instruments or other governing documents.

San Juan Basin Colorado Properties

Royalty income from the San Juan Basin Royalty Properties is calculated and paid to the Trust on a state-by-state basis depending upon whether the property is situated in Colorado and New Mexico. The majority of the royalty income from the San Juan Basin Royalty Properties is attributable to the San Juan Basin New Mexico Properties. Substantially all of the natural gas produced from the San Juan Basin Royalty Properties is currently being sold in the spot market.

Royalty Income. Royalty income attributable to the San Juan Basin Colorado Properties for the years ended December 31, 2017 and 2016 was $617,699 and $255,388, respectively. The increase of approximately 142% for the year ended December 31, 2017 as compared to December 31, 2016 was primarily due to lower operating costs, increased net natural gas production volumes and higher prices for natural gas from the San Juan Basin Colorado Properties.

Operating Costs and Capital Expenditures. Operating costs attributable to the San Juan Basin Colorado Properties for the years ended December 31, 2017 and 2016 were $148,391 and $286,173, respectively. The operators have informed the Trust that the decrease of approximately 48% for the year ended December 31, 2017 as compared to December 31, 2016 was primarily due to decreased joint venture billings in 2017. Capital expenditures attributable to the San Juan Basin Colorado Properties for the years ended December 31, 2017 and 2016 were $0 and $0, respectively.

	2017			**2016**		
	Natural Gas	**Natural Gas Liquids**	**Oil and Condensate**	**Natural Gas**	**Natural Gas Liquids**	**Oil and Condensate**
Average sales price	$ 1.61			$ 1.21		
	(Mcf)	**(Bbls)**	**(Bbls)**	**(Mcf)**	**(Bbls)**	**(Bbls)**
Actual production volumes attributable to the Royalty paid for Hugoton Royalty Properties	474,822			497,758		
Net production volumes attributable to the Royalty paid for Hugoton Royalty Properties	383,409			210,532		

San Juan Basin New Mexico Properties

Royalty Income. Royalty income attributable to the San Juan Basin New Mexico Properties for the years ended December 31, 2017 and 2016 was $1,085,082 and $652,108, respectively. The increase of approximately 66% for the year ended December 31, 2017 as compared to December 31, 2016 was primarily due to higher prices for natural gas, natural gas liquids and oil and condensate, increased net production volumes for natural gas and natural gas liquids and lower capital expenditures, partially offset by higher operating costs for the San Juan Basin New Mexico Properties.

Table of Contents

Operating Costs and Capital Expenditures. Operating costs attributable to the San Juan Basin New Mexico Properties for the years ended December 31, 2017 and 2016 were $873,736 and $862,283, respectively. Capital expenditures attributable to the San Juan Basin New Mexico Properties for the years ended December 31, 2017 and 2016 were $10,777 and $39,061, respectively. Hilcorp has informed the Trust that decrease of approximately 72% for the year ended December 31, 2017 as compared to December 31, 2016 was primarily due to discontinuing new capital project spending after the Purchase and Sales Agreement between ConocoPhillips and Hilcorp was executed in April 2017.

	2017			2016		
	Natural Gas	**Natural Gas Liquids**	**Oil and Condensate**	**Natural Gas**	**Natural Gas Liquids**	**Oil and Condensate**
Average sales price	$ 2.20	$ 16.17	$ 37.91	$ 1.64	$ 12.40	$ 31.25
	(Mcf)	**(Bbls)**	**(Bbls)**	**(Mcf)**	**(Bbls)**	**(Bbls)**
Actual production volumes attributable to the Royalty paid for Hugoton Royalty Properties	619,375	45,105	1,419	636,544	47,665	1,874
Net production volumes attributable to the Royalty paid for Hugoton Royalty Properties	341,305	18,771	774	267,253	15,142	829

Effective September 2017, following Hilcorp's acquisition of ConocoPhillips' interests in the San Juan New Mexico Properties, Hilcorp continued to make an estimated payment of Net Proceeds to the Trust each month consistent with the monthly amount previously paid by ConocoPhillips. These estimated payments remain subject to reconciliation with respect to actual revenue, costs and net proceeds, and the effects of pricing during the prior months after Hilcorp has completed its transition as owner of the San Juan New Mexico Properties. The reconciliation and true-up of the estimated payments for this transition period may affect the Trust's future receipt of Net Proceeds from Hilcorp.

Off-Balance Sheet Arrangements

None.

Contractual Obligations

None.

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;

35

Table of Contents

(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 generally accepted accounting principles in the United States 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.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Unitholders of Mesa Royalty Trust and Bank of New York Mellon, as Trustee:

Opinion on the Financial Statements

We have audited the accompanying statements of assets, liabilities and trust corpus of Mesa Royalty Trust (the Trust) as of December 31, 2017 and 2016, the related statements of distributable income and changes in trust corpus for each of the years in the two-year period ended December 31, 2017, and the related notes (collectively, the financial statements). In our opinion, the financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of the Trust as of December 31, 2017 and 2016, and its distributable income and changes in trust corpus for each of the years in the two-year period ended December 31, 2017, in conformity with the modified cash basis of accounting described in Note 2.

Basis of Accounting

As described in Note 2, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

Basis for Opinion

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 are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by the Trustee, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

(signed) KPMG LLP

We have served as the Trust's auditor since 2002.

Houston, Texas
April 2, 2018

Table of Contents

Item 8. Financial Statements and Supplementary Data.

MESA ROYALTY TRUST

STATEMENTS OF DISTRIBUTABLE INCOME

	Years Ended December 31, 2017	2016
Royalty income	$ 3,028,793	$ 1,364,791
Interest income	10,221	1,899
General and administrative expenses	(100,795)	(152,778)
Distributable income	$ 2,938,219	$ 1,213,912
Distributable income per unit	$ 1.5766	$ 0.6514

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31, 2017	2016
ASSETS		
Cash and short-term investments	$ 1,801,613	$ 1,604,112
Net overriding royalty interests in oil and gas properties	42,498,034	42,498,034
Accumulated amortization	(40,519,773)	(40,058,695)
Total assets	$ 3,779,874	$ 4,043,451
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 681,942	$ 604,112
Trust corpus (1,863,590 units of beneficial interest, issued and outstanding)	3,097,932	3,439,339
Total liabilities and trust corpus	$ 3,779,874	$ 4,043,451

STATEMENTS OF CHANGES IN TRUST CORPUS

	Years Ended December 31, 2017	2016
Trust corpus, beginning of year	$ 3,439,339	$ 3,727,980
Distributable income	2,938,219	1,213,912
Distributions to unitholders	(2,818,548)	(1,207,174)
Amortization of net overriding royalty interests	(461,078)	(295,379)

Trust corpus, end of year	$	3,097,932	$	3,439,339

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

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS

Note 1 Trust Organization and Provisions

Trust Corpus Description. The Mesa Royalty Trust (the "Trust") was created on November 1, 1979, and is now governed by the Mesa Royalty Trust Indenture (as amended, the "Trust Indenture"). Through a series of conveyances, assignments, and acquisitions, the Trust currently owns an overriding royalty interest (the "Royalty") equal to 11.44% of 90% of the Net Proceeds (as defined in the Conveyance and described below) attributable to the specified interest in certain producing oil and gas properties located in the:

- Hugoton field of Kansas (the "Hugoton Royalty Properties");

- San Juan Basin field of New Mexico (the "San Juan Basin New Mexico Properties"); and

- San Juan Basin field of Colorado (the "San Juan Basin Colorado Properties", and together with the "San Juan Basin New Mexico Properties, the "San Juan Basin Royalty Properties", and together with the Hugoton Royalty Properties and the San Juan Basin Royalty Properties, the "Royalty Properties").

Trust Corpus Conveyance History. On November 1, 1979, Mesa Petroleum Co., predecessor to Mesa Limited Partnership ("MLP"), which was the predecessor to MESA Inc., conveyed to the Trust 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 the Royalty Properties described above. The Royalty is evidenced by counterparts of an Overriding Royalty Conveyance, dated November 1, 1979 (the "Conveyance"). 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 1985 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.

Hugoton Royalty Properties. Until August 7, 1997, MESA Inc. operated the Hugoton Royalty Properties through Mesa Operating Co., its wholly owned subsidiary. 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 were operated by PNR until December 31, 2014, at which point Linn Energy Holdings, LLC, a subsidiary of Linn Energy, LLC ("Old Linn") took over as operator. Pursuant to the bankruptcy proceedings and court-approved plans of reorganization involving Old Linn, which are described in detail below, Linn Energy, Inc. (together with its subsidiaries, "Linn") became the operator of the Hugoton Royalty Properties on February 28, 2017. Linn currently operates the Hugoton Royalty Properties.

San Juan Basin Colorado Properties. On April 30, 1991, MLP sold to Conoco, Inc. ("ConocoPhillips") its interests in the San Juan Basin Royalty Properties (the "San Juan Basin Sale"). The Trust's interest in the San Juan Basin Royalty Properties was conveyed from PNR's working interest in 31,328 net producing acres in northwestern New Mexico and southwestern Colorado. ConocoPhillips sold the portion of its interests in the San Juan Basin Colorado Properties to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company ("Red Willow") (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Trust Organization and Provisions (Continued)

substantially all of its interest in the San Juan Basin Colorado Properties to BP Amoco Company ("BP"). BP and Red Willow currently operate the San Juan Basin Colorado Properties.

San Juan Basin New Mexico Properties. Starting from the date of the San Juan Basin Sale and ending on July 31, 2017, ConocoPhillips operated substantially all of the San Juan Basin New Mexico Properties, except an immaterial number of properties assigned to XTO Energy, Inc. ("XTO") effective January 1, 2005. On July 31, 2017, ConocoPhillips sold its San Juan Basin assets to Hilcorp San Juan LP ("Hilcorp"), an affiliate of Hilcorp Energy Company.

As used in this report, Linn refers to the current operator of the Hugoton Royalty Properties, Hilcorp refers to the current operator of the San Juan Basin New Mexico Properties, and BP and Red Willow refers to the current co-operators of certain tracts of land included in the San Juan Basin Colorado Properties, unless otherwise indicated.

Trustee and Terms of Trust Indenture. Effective October 2, 2006, the Bank of New York Mellon Trust Company, N.A. (the "Trustee") succeeded JP Morgan Chase Bank, N.A. as Trustee of the Trust. JPMorgan Chase Bank, N.A. is the successor by mergers to the originally named Trustee, Texas Commerce Bank National Association. The Trust is a passive entity whose purposes are limited to: (1) converting the Royalties to cash, either by retaining them and collecting the proceeds of production (until production has ceased or the Royalties are otherwise terminated) or by selling or otherwise disposing of the Royalties; and (2) distributing such cash, net of amounts for payments of liabilities to the Trust, to the unitholders. The Trust has no sources of liquidity or capital resources other than the revenues, if any, attributable to the Royalties and interest on cash held by the Trustee as a reserve for liabilities or for distribution. The terms of 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 by the unitholders;

(c) the Trustee can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge 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 2;

(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 two successive years is less than $250,000 per year or (ii) a vote by the unitholders in favor of termination. Upon termination of the Trust, the Trustee will sell for cash all the assets held in the Trust estate and make a final distribution to unitholders of any funds remaining after all Trust liabilities have been satisfied; and

(f) Linn, Hilcorp and BP (each a "Working Interest Owner", and 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.

Trustee's Fees. Pursuant to the Trust Indenture, the Trust pays the Trustee fees for its services each quarter and the Working Interest Owners partially reimburse the Trust for the fees paid in connection with the Trustee's services. The net amount of these reimbursements is included in the general and administrative expenses of the Trust. For the year ended December 31, 2017, the Trustee was due $475,000 for its services. The Trust paid $433,152 of this amount to the Trustee, and $41,848

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 1 Trust Organization and Provisions (Continued)

was allocated to offset against interest due to the Trust under the Trust Indenture. The Trust Indenture requires that cash being held by the Trustee earn interest at 1.5% below the prime rate, which would have yielded the Trust a 2.25% annualized return from January 1, 2017 through March 15, 2017, a 2.50% annualized return from March 16, 2017 through June 14, 2017, a 2.75% annualized return from June 15, 2017 through December 13, 2017, and a 3.00% annualized return from December 14, 2017 through December 31, 2017. However, due to the current interest rate environment, the Trustee was unable to obtain an account in which such an interest rate was available. In the event such an interest rate is unavailable in the future, the Trustee intends to allocate certain of its fees due to the Trust to meet the minimum interest rate payable under the Trust Indenture.

The Working Interest Owners partially reimburse the Trust each quarter for amounts paid in connection with the Trustee's services. For the year ended December 31, 2017, the Trustee's fees were $433,153 and the Working Interest Owners reimbursed a sum of $383,588 to the Trustee, which was the same amount reimbursed for the year ended December 31, 2016.

Linn Energy, LLC Reorganization. On May 11, 2016, Old Linn, LinnCo, LLC ("LinnCo"), an affiliate of Old Linn, and certain of Old Linn's direct and indirect subsidiaries (collectively with Old Linn and LinnCo, the "Debtors"), filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy Code in the United States Bankruptcy Court for the Southern District of Texas (the "Court"). The Debtors' Chapter 11 cases were administered jointly under the caption *In re Linn Energy, LLC, et al.*, Case No. 16 60040.

On January 27, 2017, the Court entered the *Order Confirming (I) Amended Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and its Debtor Affiliates Other Than Linn Acquisition Company, LLC and Berry Petroleum Company, LLC and (II) Amended Joint Chapter 11 Plan of Reorganization of Linn Acquisition Company, LLC and Berry Petroleum Company, LLC,* which approved and confirmed the Amended Joint Chapter 11 Plan of Reorganization of Linn Energy, LLC and Its Debtor Affiliates Other Than Linn Acquisition Company, LLC and Berry Petroleum Company, LLC (the "Plan"). The Plan became effective on February 28, 2017 (the "Effective Date").

Pursuant to the Plan, on the Effective Date, all assets of Old Linn (other than equity interests in Linn Acquisition Company, LLC and Berry Petroleum Company, LLC) were conveyed to Linn, and LinnCo, LLC and Linn Energy, LLC were wound down and liquidated. Subsequent to the effectiveness of the Plan, Linn Energy, Inc. is now the reorganized successor to Old Linn. Under the Plan Supplement, as amended, filed with the Court, the Debtors assumed all executory contracts and unexpired leases with the Trust and Mesa Operating Limited Partnership as the counterparty. Furthermore, pursuant to the Plan, the royalty interests in the Hugoton Royalty Properties owned by the Trust shall be preserved and remain in full force and effect in accordance with the terms of the granting instruments or other governing documents.

Note 2 Basis of Presentation

The accompanying audited financial information has been prepared by the Trustee in accordance with the instructions to Form 10-K. The preparation of the financial statements requires estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent liabilities at the date of the financial statements and the reported amounts of income and expenses during the reporting period. Actual results could differ from those estimates. The Trustee believes such

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 2 Basis of Presentation (Continued)

information includes all the disclosures necessary to make the information presented not misleading. The information furnished reflects all adjustments which are, in the opinion of the Trustee, necessary for a fair presentation of the results for the years presented. 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.

In accordance with the Conveyance, the Working Interest Owners are obligated to calculate and pay the Trust each month an amount equal to 90% of the Net Proceeds attributable to the 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.

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 because 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. 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 distribution.

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.

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 3 Legal Proceedings

There are no pending legal proceedings to which the Trust is a named party. The Trustee has been advised by the Working Interest Owners that it may be 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 are made against Royalty income, such charges could have a material impact on future Royalty income.

Note 4 Income Tax Matters

In a technical advice memorandum dated February 26, 1982, the Internal Revenue Service (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 U.S. Tax Cuts and Job Act (the "2017 Tax Act") was enacted on December 22, 2017. The 2017 Tax Act is comprehensive legislation that contains substantial changes to U.S. taxation. The Trust does not expect the new tax law to have any significant impact due to the Trust being classified as a grantor trust for U.S. income tax purposes. However, unitholders should consult with their personal tax advisors to determine how the 2017 Tax Act impacts any items of income or deduction received from the Trust.

For taxable years beginning after December 31, 2012, individuals, estates, and trusts with income above certain thresholds are subject under Section 1411 of the Internal Revenue Code to an additional 3.8% tax also known as the "net investment income tax" on their net investment income. Grantor trusts such as the Trust are not subject to the 3.8% tax; however, the unitholders may be subject to the tax. For these purposes, investment income would generally include certain income derived from investments, such as the royalty income derived from the units and gain realized by a unitholder from a sale of units.

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., 601 Travis Street, Floor 16, Houston, Texas 77002, telephone number 713-483-6020, 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. 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.

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 5 Excess Production Costs

		As of December 31, 2017		As of December 31, 2016
San Juan Basin Colorado Properties BP	$		$	3,860
San Juan Basin Colorado Properties Red Willow		15,944		12,532
San Juan Basin New Mexico Properties XTO		6,070		3,591
Total	$	22,014	$	19,983

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. The excess production costs must be recovered by the Working Interest Owners before any distribution of Royalty income from the Royalty Properties which are operated by such Working Interest Owners will be made to the Trust.

Note 6 Distributable Income Per Unit

During 2011, the Trustee, acting pursuant to the Trust Indenture, withheld $1.0 million for future unknown contingent liabilities and expenses (such cumulative withholding being the "Contingent Reserve"). The Trustee reserves the right to determine whether or not to release cash reserves in future periods with respect to any reimbursement expenses. At any given time, the Contingent Reserve is included in cash and short term investments.

For the year ended December 31, 2017, the Trustee increased the Contingent Reserve by (i) $82,244 of Royalty income received from BP in March 2017 after the distribution to unitholders had been announced for the month of March 2017, which Royalty income was included in the April 2017 distribution to unitholders, (ii) $47,840 of Royalty income received from BP in June 2017 after the distribution to unitholders had been announced for the month of June 2017, which Royalty income was included in the July 2017 distribution to unitholders, (iii) $1,307 for the amount of September expected expense reimbursement cash receipts, received in October 2017, (iv) $49,211 of Royalty income received from BP in December 2017 after the distribution to unitholders had been announced for the month of December 2017, which Royalty income was included in the January 2018 distribution to unitholders, and (v) $70,460 of December 2017 expenses that was included in the distribution calculation for December 2017, but not paid by the Trust until January 2018. For the year ended December 31, 2017, the Trustee decreased the Contingent Reserve by (i) $82,244 and $47,840 of aggregate Royalty income received from BP in March 2017 and June 2017, respectively, and (ii) $1,307 for expected expense reimbursement cash receipts. The net effects of the foregoing adjustments for the year ended December 31, 2017 resulted in the balance of the Contingent Reserve being equal to $1,119,671 as of December 31, 2017.

For the year ended December 31, 2016, the Trustee increased the Contingent Reserve by (i) the amounts received during the first quarter and third quarter of 2016 related to expense reimbursement cash receipts for previous periods totaling $6,738 and $812, respectively, (ii) a prior period expense refund received from a vendor in the amount of $101 and (iii) $107,659 of royalty income received from BP in September 2016 after the distribution to unitholders had been announced for the month of September 2016, which Royalty income was included in the October 2016 distribution to unitholders. For the twelve months ended December 31, 2016, the Trustee decreased the reserve for future

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 6 Distributable Income Per Unit (Continued)

unknown contingent liabilities and expenses for (i) a prior period expense refund received from a vendor in the amount of $101, (ii) the amount of expected expense reimbursement cash receipts of $812 and (iii) $107,659 of Royalty income received from BP in September 2016 after the distribution to unitholders had been announced for the month of September 2016, which Royalty income was included in the October 2016 distribution to unitholders. The net effects of the foregoing adjustments for the year ended December 31, 2016 resulted in the balance of the Contingent Reserve being equal to $1,000,000 as of December 31, 2016.

For the year ended December 31, 2016, the Trustee decreased the Contingent Reserve by the amount of expected expense reimbursement cash receipts of $108,572 and increased the Contingent Reserve by the amounts received during 2016 related to expense reimbursement cash receipts for previous periods totaling $115,310. The net effects on distributable income per unit for the years ended December 31 are as follows:

	2017	2016
Distributable Income	$ 2,938,219	$ 1,213,912
Increase in the Contingent Reserve	(251,062)	(115,310)
Withdrawal from the Contingent Reserve	131,391	108,572
Distributable Income Available for Distribution	$ 2,818,548	$ 1,207,174
Distributable Income Available for Distribution per unit	$ 1.5124	$ 0.6478
Units outstanding	1,863,590	1,863,590

Note 7 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 nontraditional resources the definition of oil and gas producing activities will expand and focus on the marketable product rather than the method of extraction.

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 7 Supplemental Reserve Information (Unaudited) (Continued)

Estimates of the proved oil and gas reserves attributable to the Hugoton and San Juan Basin Royalty Properties as of December 31, 2017, 2016, 2015, 2014, and 2013 are based on reserve 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 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, 2017 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 future Royalty income; (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, proved developed, and proved undeveloped 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 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)

Note 7 Supplemental Reserve Information (Unaudited) (Continued)

ESTIMATED QUANTITIES OF PROVED, PROVED DEVELOPED, AND PROVED UNDEVELOPED RESERVES (Unaudited)

	Oil and Condensate (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Reserves:			
December 31, 2013	7,525	304,362	4,967,069
Revisions to previous estimates	4,034	154,309	2,229,311
Extensions, discoveries and other additions			
Production	(1,377)	(71,145)	(992,805)
December 31, 2014	10,182	387,526	6,203,575
Revisions to previous estimates	(2,955)	(61,770)	(391,926)
Extensions, discoveries and other additions			
Production	(932)	(38,737)	(561,855)
December 31, 2015	6,295	287,019	5,249,794
Revisions to previous estimates	(228)	(29,399)	(566,548)
Extensions, discoveries and other additions			
Production	(829)	(24,750)	(599,447)
December 31, 2016	5,238	232,870	4,083,799
Revisions to previous estimates	3,713	161,831	3,214,039
Extensions, discoveries and other additions			
Production	(774)	(34,692)	(987,502)
December 31, 2017	8,177	360,009	6,310,336
Proved Developed Reserves:			
December 31, 2013	7,525	304,362	4,967,069
December 31, 2014	10,182	387,526	6,203,575

December 31, 2015	6,295	287,019	5,249,794
December 31, 2016	5,238	232,870	4,083,799
December 31, 2017	8,177	360,009	6,310,336
Proved Undeveloped Reserves:			
December 31, 2013			
December 31, 2014			
December 31, 2015			
December 31, 2016			
December 31, 2017			

The Hugoton Royalty represents 20%, 15% and 23% of the estimated proved natural gas liquids reserves and 21%, 15% and 22% of the estimated proved natural gas reserves as of December 31, 2017, 2016 and 2015, respectively.

The December 31, 2017, 2016, 2015, 2014 and 2013 reserve estimates for the Hugoton Royalty Properties were prepared by a third party reservoir engineering firm.

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 7 Supplemental Reserve Information (Unaudited) (Continued)

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

	As of December 31,		
	2017	2016	2015
	(In thousands)		
The Trust's proportionate share of future Gross Proceeds	$ 49,439	$ 31,108	$ 40,987
The Trust's proportionate share of future operating costs	(25,507)	(19,336)	(23,495)
Future capital costs	(1)	(1)	(1)
Future Royalty income	$ 23,931	$ 11,771	$ 17,491
Discount at 10% per annum	(10,585)	(4,714)	(6,767)
Standardized measure of future Royalty income from proved oil and gas reserves	$ 13,346	$ 7,057	$ 10,724

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

	As of December 31,		
	2017	2016	2015
	(In thousands)		
Standardized measure of future Royalty income from proved oil and gas reserves at beginning of year	$ 7,057	$ 10,724	$ 19,324
Revisions of previous estimates	549	1,741	2,695
Net changes in price and production costs	7,115	(2,171)	11,309
Royalty income	(3,029)	(1,365)	(2,077)
Accretion of discount	1,654	1,610	2,091
Net changes in standardized measure	$ 6,289	$ (3,667)	$ 8,600
Standardized measure of future Royalty income from proved oil and gas reserves at end of year	$ 13,346	$ 7,057	$ 10,724

The Hugoton Royalty represents approximately 31% and 21.7% of the standardized measure of future royalty income for 2017 and 2016, respectively.

Standardized measure at December 31, 2017 was calculated using natural gas prices of $3.65 per Mcf for Hugoton Royalty Properties and $2.81 for the San Juan Basin Royalty Properties, natural gas liquids prices of $22.85 per Bbl for Hugoton Royalty Properties and $17.25 per Bbl for the San Juan Basin Royalty Properties, and oil and condensate prices of $35.91 per Bbl for the San Juan Basin Royalty Properties.

Table of Contents

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

Note 8 Selected Quarterly Financial Data (Unaudited)

	Summarized Results for the Quarters Ended			
	March 31	June 30	September 30	December 31
2017:				
Royalty income	$ 918,539	$ 717,229	$ 626,384	$ 766,641
Distributable income	$ 871,646	$ 669,696	$ 593,957	$ 802,920
Distributable income per unit	$ 0.4677	$ 0.3594	$ 0.3187	$ 0.4308
2016:				
Royalty income	$ 204,645	$ 182,988	$ 451,782	$ 525,376
Distributable income	$ 156,222	$ 145,135	$ 416,102	$ 496,453
Distributable income per unit	$ 0.0838	$ 0.0779	$ 0.2233	$ 0.2664

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. 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 and information related to the Trustee's review of certain information and calculations by the Working Interest Owners.

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, and on the basis of accounting as described in Note 2 in the Notes to Financial Statements under Item 8 of this Form 10-K. The Trustee conducted an evaluation of the effectiveness of the Trust's internal control over financial reporting ("internal control over financial reporting") based on the criteria established in "*Internal Control Integrated Framework (2013)*" 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 (2013),*" the Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2017.

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 Trust. 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 corporate trustee'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.

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 2017.

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 Trust's financial statements for the years ended December 31, 2017 and 2016, as well as fees billed for other services rendered by KPMG LLP.

	2017	2016
Audit fees(1)	$ 525,000	$ 525,000
Audit-related fees		
Tax fees(2)	86,000	86,000
All other fees		
Total fees	$ 611,000	$ 611,000

(1) Audit fees consist of fees for the audit of the Trust's financial statements, and reimbursement of expenses related to the audit and quarterly reviews for the years ended December 31, 2017 and 2016. The Trust is reimbursed by the Working Interest Owners for approximately 88.56% of all general and administrative expenses incurred.

(2) Tax fees consist of fees related to the Trust's tax information for its unitholders, which includes work performed on the taxes, returns and other items billed during the years ended December 31, 2017 and 2016. The Trust is reimbursed by the Working Interest Owners

for approximately 88.56% of all general and administrative expenses incurred.

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 Form 10-K on the pages indicated.

(a)(2) Schedules

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

(a)(3) Exhibits

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. The Bank of New York Trust Company, N.A. is the successor trustee to JPMorgan Chase Bank, N.A. JP Morgan Chase Bank, N.A. is the successor by mergers to the originally named Trustee, Texas Commerce Bank National Association.)

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

* Previously filed in paper format 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/ MICHAEL J. ULRICH

Michael J. Ulrich
Vice President

April 2, 2018

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

Auditors	**Counsel**	**Transfer Agent and Registrar**
KPMG LLP Houston, Texas	Andrews Kurth Kenyon LLP Houston, Texas	The Bank of New York Trust Company, N.A. Houston, Texas 77002
	Mesa Royalty Trust 601 Travis Street, Floor 16 Houston, Texas 77002	

This Form 10-K was distributed to unitholders as an Annual Report. Additional copies of this Annual Report will be provided, free of 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: Michael J. Ulrich
601 Travis Street, Floor 16
Houston, Texas 77002

This information may also be obtained free of charge from the Trust's website:
http://mtr.investorhq.businesswire.com/