MESA ROYALTY TRUST/TX
Form 10-Q
November 12, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the Quarterly Period ended September 30, 2013

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

For the Transition Period from to
Commission File Number: 1-7884

MESA ROYALTY TRUST

(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of Incorporation or Organization)	**76-6284806** (I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A., Trustee 919 Congress Avenue Austin, Texas (Address of Principal Executive Offices)	**78701** (Zip Code)

1-800-852-1422
(Registrant's Telephone Number, Including Area Code)

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

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

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

As of November 12, 2013 1,863,590 Units of Beneficial Interest were outstanding in Mesa Royalty Trust.

PART I FINANCIAL INFORMATION

Item 1. Financial Statements.

MESA ROYALTY TRUST

STATEMENTS OF DISTRIBUTABLE INCOME

(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Royalty income	$ 917,038	$ 737,229	$ 2,646,517	$ 2,926,291
Interest income	23	80,040	107	80,137
General and administrative expense	(33,227)	(128,460)	(123,360)	(235,424)
Distributable income	$ 883,834	$ 688,809	$ 2,523,264	$ 2,771,004
Distributable income per unit	$ 0.4743	$ 0.3696	$ 1.3540	$ 1.4869
Units outstanding	1,863,590	1,863,590	1,863,590	1,863,590

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Cash and short-term investments	$ 1,883,834	$ 1,830,390
Net overriding royalty interest in oil and gas properties	42,498,034	42,498,034
Accumulated amortization	(38,611,899)	(38,013,221)
Total assets	$ 5,769,969	$ 6,315,203
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 883,834	$ 830,390
Trust corpus (1,863,590 units of beneficial interest authorized, issued and outstanding)	4,886,135	5,484,813
Total liabilities and trust corpus	$ 5,769,969	$ 6,315,203

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

MESA ROYALTY TRUST

STATEMENTS OF CHANGES IN TRUST CORPUS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Trust corpus, beginning of period	$ 5,097,176	$ 5,821,564	$ 5,484,813	$ 6,086,698
Distributable income	883,834	688,809	2,523,264	2,771,004
Distributions to unitholders	(883,834)	(688,809)	(2,523,264)	(2,771,004)
Amortization of net overriding royalty interest	(211,041)	(119,878)	(598,678)	(385,012)
Trust corpus, end of period	$ 4,886,135	$ 5,701,686	$ 4,886,135	$ 5,701,686

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

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS

(Unaudited)

Note 1 Trust Organization and Provisions

The Mesa Royalty Trust (the "Trust") was created on November 1, 1979. On that date, Mesa Petroleum Co., predecessor to Mesa Limited Partnership ("MLP") which was the predecessor to MESA Inc., conveyed to the Trust an overriding royalty interest (the "Royalty") equal to 90% of the Net Proceeds (as defined in the Conveyance and described below) attributable to the specified interests in properties conveyed by the assignor on that date (the "Subject Interests"). The Subject Interests consisted of interests in certain producing oil and gas properties located in the Hugoton field of Kansas, the San Juan Basin field of New Mexico and Colorado and the Yellow Creek field of Wyoming (the "Royalty Properties"). The Royalty is evidenced by counterparts of an Overriding Royalty Conveyance dated as of November 1, 1979 (the "Conveyance"). On April 30, 1991, MLP sold its interests in the Royalty Properties located in the San Juan Basin field to ConocoPhillips. ConocoPhillips sold the portion of its interests in the San Juan Basin Royalty Properties located in Colorado to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the Colorado San Juan Basin Royalty Properties to BP Amoco Company ("BP"), a subsidiary of BP p.l.c. Until August 7, 1997, MESA Inc. operated the Hugoton Royalty Properties through Mesa Operating Co., a wholly owned subsidiary of MESA Inc. On August 7, 1997, MESA Inc. merged with and into Pioneer Natural Resources Company ("Pioneer"), formerly a wholly owned subsidiary of MESA Inc., and Parker & Parsley Petroleum Company merged with and into Pioneer Natural Resources USA, Inc. (successor to Mesa Operating Co.), a wholly owned subsidiary of Pioneer ("PNR") (collectively, the mergers are referred to herein as the "Merger"). Subsequent to the Merger, the Hugoton Royalty Properties have been operated by PNR. Substantially all of the San Juan Basin Royalty Properties located in New Mexico are operated by ConocoPhillips. Effective January 1, 2005, ConocoPhillips assigned its interest in an immaterial number of San Juan Basin Royalty Properties located in New Mexico to XTO Energy Inc. The San Juan Basin Royalty Properties located in Colorado are operated by BP. As used in this report, PNR refers to the operator of the Hugoton Royalty Properties, ConocoPhillips refers to the operator of the San Juan Basin Royalty Properties, other than the portion of such properties located in Colorado, and BP refers to the operator of the Colorado San Juan Basin Royalty Properties unless otherwise indicated.

Effective October 2, 2006, The Bank of New York Mellon Trust Company, N.A. (the "Trustee") succeeded JPMorgan Chase Bank, N.A. as Trustee of the Trust. JPMorgan Chase Bank, N.A. is the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association. The terms of the Mesa Royalty Trust Indenture (the "Trust Indenture") provide, among other things, that:

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

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

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

Note 1 Trust Organization and Provisions (Continued)

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

During 2011, the Trustee withheld $1.0 million for future unknown contingent liabilities and expenses in accordance with the Trust Indenture. As of September 30, 2013 the $1.0 million is included in cash and short-term investments.

For the quarter ended September 30, 2013, The Bank of New York Mellon Trust Company, N.A. was paid fees totaling $85,636 in connection with services performed in its capacity as Trustee. These fees have been reimbursed by the working interest owners in accordance with the Trust Indenture. These reimbursements totaled $75,839.

Note 2 Basis of Presentation

The accompanying unaudited financial information has been prepared by the Trustee in accordance with the instructions to Form 10-Q. 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 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 interim periods presented. The financial information should be read in conjunction with the financial statements and notes thereto included in the Trust's Annual Report on Form 10-K for the year ended December 31, 2012. 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 (as defined in the Conveyance) attributable to the month. In 1985, the Trust Indenture was amended and the Trust conveyed to an affiliate of Mesa Petroleum Co. 88.5571% of the original Royalty (such transfer, the "1985 Assignment"). The effect of the 1985 Assignment was an overall reduction of approximately 88.56% in

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

Note 2 Basis of Presentation (Continued)

the size of the Trust. As a result, the Trust is now entitled to receive 11.44% of 90% of the Net Proceeds attributable to each month.

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

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

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

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

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

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

Note 3 Legal Proceedings

There are no pending legal proceedings to which the Trust is a named party. The Trustee has been advised by PNR, ConocoPhillips and BP Amoco that it is subject to litigation in the ordinary course of business for certain matters that include the Royalty Properties. While each of the working interest owners has advised the Trustee that it does not currently believe any of the pending litigation will have a material adverse effect net to the Trust, in the event such matters were adjudicated or settled in a material amount and charges were made against Royalty income, such charges could have a material impact on future Royalty income.

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

Note 4 Income Tax Matters

In a technical advice memorandum dated February 26, 1982, the IRS advised the Dallas District Director that the Trust is classifiable as a grantor trust and not as an association taxable as a corporation. As a grantor trust, the Trust incurs no federal income tax liability and each unitholder is subject to tax on the unitholder's pro rata share of the income and expense of the Trust as if the unitholder were the direct owner of a pro rata share of the Trust's assets. In addition, there is no state tax liability for the 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., 919 Congress Avenue, Austin, Texas 78701, telephone number 1-800-852-1422, is the representative of the Trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT.

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

Note 5 Excess Production Costs

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 properties will be made to the Trust. As of September 30, 2013 and December 31, 2012, there were no excess production costs on the Trust Properties.

Note 6 Tax Assessment

PNR has advised the Trustee that it received a proposed assessment from the Kansas Department of Revenue on September 10, 2009, for additional tax, penalty and interest of approximately $4.1 million resulting primarily from the settlement of the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.* in early 2007. The portion of the tax assessment net to the Trust is approximately $181,000, which could adversely affect Trust distributions. PNR has submitted a written response objecting to the proposed assessment. On March 25, 2010, the Kansas Department of Revenue issued a final assessment, which included additional interest and penalties, increasing the amount assessed to approximately $4.5 million.

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

Note 6 Tax Assessment (Continued)

The portion of the tax assessment net to the Trust is approximately $197,000, which could adversely affect Trust distributions. On June 24, 2011, the hearing examiner of the Department of Revenue upheld the earlier assessment. PNR has filed an appeal to the Court of Tax Appeals in Kansas. No assurance can be made that any objections of disputed items raised by PNR will be successful.

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

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following review of the Trust's financial condition and results of operations should be read in conjunction with the financial statements and notes thereto. The discussion of net production attributable to the Hugoton and San Juan properties represents production volumes that are to a large extent hypothetical as the Trust does not own and is not entitled to any specific production volumes. See Note 9 to the financial statements in the Trust's Annual Report on Form 10-K for the year ended December 31, 2012. 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 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.

Note Regarding Forward-Looking Statements

This Form 10-Q includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-Q, including without limitation the statements under "Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements. Although the Working Interest Owners have advised the Trust that they believe that the expectations reflected in the forward-looking statements contained herein are reasonable, no assurance can be given that such expectations will prove to be correct. Important factors that could cause actual results to differ materially from expectations ("Cautionary Statements") are disclosed in this Form 10-Q and in the Trust's Annual Report on Form 10-K for the year ended December 31, 2012, including under "Item 1A. Risk Factors". All subsequent written and oral forward-looking statements attributable to the Trust or persons acting on its behalf are expressly qualified in their entirety by the Cautionary Statements.

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

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 defined in the Conveyance. The following summary illustrates the net effect of the components of the actual Royalty computation for the periods indicated.

	Three Months Ended September 30,			
	2013		2012	
	Natural Gas	Oil, Condensate and Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids
The Trust's proportionate share of Gross Proceeds(1)	$ 1,153,740	$ 692,864	$ 703,097	$ 761,245
Less the Trust's proportionate share of:				
Capital costs recovered	(242,229)	(154,038)	(49,212)	(74,298)
Operating costs	(280,946)	(252,353)	(302,396)	(301,207)
Royalty income	$ 630,565	$ 286,473	$ 351,489	$ 385,740
Average realized price(2)	$ 3.05	$ 25.84	$ 1.91	$ 27.19
Average production costs(3)	$ 2.53	$ 36.66	$ 1.91	$ 26.47
	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Net production volumes attributable to the Royalty paid(4)	206,497	11,085	184,305	14,186

	Nine Months Ended September 30,			
	2013		2012	
	Natural Gas	Oil, Condensate and Natural Gas Liquids	Natural Gas	Oil, Condensate and Natural Gas Liquids
The Trust's proportionate share of Gross Proceeds(1)	$ 3,159,487	$ 2,215,291	$ 2,522,633	$ 2,999,637
Less the Trust's proportionate share of:				
Capital costs recovered	(462,815)	(383,302)	(195,668)	(422,693)
Operating costs	(1,042,616)	(839,528)	(925,595)	(1,052,023)
Royalty income	1,654,056	992,461	1,401,370	1,524,921
Average realized price(2)	$ 2.98	$ 27.31	$ 2.30	$ 33.32
Average production costs(3)	$ 2.71	$ 33.65	$ 1.84	$ 32.23
	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Net production volumes attributable to the Royalty paid(4)	554,877	36,341	607,975	45,760

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

(2) Average realized price attributable to the Royalty is calculated as Royalty Income divided by stated net production volumes attributable to the Royalty paid.

(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. 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 realized price received.

Three Months Ended September 30, 2013 and 2012

Financial Review

	Three Months Ended September 30, 2013	2012
Royalty income	$ 917,038	$ 737,229
Interest income	23	80,040
General and administrative expense	(33,227)	(128,460)
Distributable income	$ 883,834	$ 688,809
Distributable income per unit	$ 0.4743	$ 0.3696
Units outstanding	1,863,590	1,863,590

The Trust's Royalty income was $917,038 in the third quarter of 2013, an increase of approximately 24% as compared to $737,229 in the third quarter of 2012, primarily as a result of higher natural gas prices and decreased operating costs, offset in part by increased capital expenditures and lower natural gas liquids prices, in the third quarter of 2013 as compared to the third quarter of 2012.

The distributable income of the Trust for each period includes the Royalty income received from the working interest owners during such period, plus interest income earned to the date of distribution (if any). Trust administration expenses are deducted in the computation of distributable income. Distributable income for the quarter ended September 30, 2013 was $883,834, representing $0.4743 per unit, compared to $688,809, representing $0.3696 per unit, for the quarter ended September 30, 2012. Based on 1,863,590 units outstanding for the quarters ended September 30, 2013 and 2012, respectively, the per unit distributions were as follows:

	2013	2012
July	$ 0.1064	$ 0.1154
August	0.2294	0.1033
September	0.1385	0.1509
	$ 0.4743	$ 0.3696

During 2011, the Trustee withheld $1.0 million for future unknown contingent liabilities and expenses in accordance with the Trust Indenture. As of September 30, 2013 the $1.0 million is included in cash and short-term investments.

Operational Review

Hugoton Field

Natural gas and natural gas liquids production attributable to the Royalty from the Hugoton field accounted for approximately 25% of the Royalty income of the Trust during the third quarter of 2013.

PNR has advised the Trust that since June 1, 1995 natural gas produced from the Hugoton field has generally been sold under short-term and multi-month contracts at market clearing prices to multiple purchasers. During 2013 to date and 2012, the primary purchaser was Oneok Gas

Marketing, Inc. PNR has advised the Trust that it expects to continue to market gas production from the Hugoton field under short-term and multi-month contracts. As discussed below, overall market prices received for natural gas from the Hugoton Royalty Properties were higher in the third quarter of 2013 compared to the third quarter of 2012.

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. This contract has renewed on a year-to-year basis being effective June 1, 2001. The contract is renewed a year in advance, so PNR extended the contract to June 1, 2014. Pursuant to the Gas Transportation Agreement, WRI agreed to compress and transport up to 160 MMcf per day of gas and redeliver such gas to PNR at the inlet of PNR's Satanta Plant. PNR agreed to pay WRI a fee of $0.06 per Mcf escalating 4% annually as of June 1, 1996. This Gas Transportation Agreement was assigned to Oneok Field Services.

Royalty income attributable to the Hugoton Royalty decreased to $227,542 in the third quarter of 2013 from $249,808 in the third quarter of 2012 primarily due to increased capital expenditures, lower natural gas liquids prices and decreased natural gas production volumes from the Hugoton Royalty Properties, offset in part by increased natural gas prices. The average price received in the third quarter of 2013 for natural gas and natural gas liquids sold from the Hugoton Royalty Properties was $4.24 per Mcf and $30.27 per barrel, respectively, as compared to $2.39 per Mcf and $31.51 per barrel, respectively, in the third quarter of 2012. Net production of natural gas attributable to the Hugoton Royalty decreased to 34,942 Mcf in the third quarter of 2013 from 56,431 Mcf in the third quarter of 2012. Net production of natural gas liquids attributable to the Hugoton Royalty decreased from 3,648 barrels in the third quarter of 2012 to 2,623 barrels in the third quarter of 2013. Actual production volumes from the Hugoton properties decreased to 112,262 Mcf of natural gas and increased to 8,274 barrels of natural gas liquids in the third quarter of 2013 as compared to 124,330 Mcf of natural gas and 8,051 barrels of natural gas liquids for the same period in 2012. The decrease in actual natural gas volume was due to natural production decline.

The Hugoton capital expenditures were $207,382 in the third quarter of 2013, an increase of approximately 3,984% as compared to $5,078 in the third quarter of 2012 due to additional developmental drilling. Operating costs were $291,626 in the third quarter of 2013, a decrease of approximately 1% as compared to $296,046 in the third quarter of 2012.

San Juan Basin

Natural gas and natural gas liquids production attributable to the Royalty from the San Juan Basin accounted for approximately 75% of the Royalty income of the Trust during the third quarter of 2013.

Royalty income from the San Juan Basin Royalty Properties is calculated and paid to the Trust on a state-by-state basis. Substantially all of the royalty income from the San Juan Basin Royalty Properties is attributable to the Royalty Properties located in the State of New Mexico.

Royalty income from the San Juan Basin New Mexico was $462,510 during the third quarter of 2013 as compared with Royalty income $449,669 during the third quarter of 2012. The increase in Royalty income was due primarily to an increase in natural gas prices and natural gas production volumes in the third quarter of 2013 compared to the third quarter of 2012, offset in part by higher capital expenditures and operating costs, a decrease in natural gas liquids production and lower natural gas liquids prices for the third quarter of 2013 compared to the third quarter of 2012. Net production attributable to the San Juan Basin Royalty located in New Mexico was 88,382 Mcf of natural gas and 8,463 barrels of natural gas liquids in the third quarter of 2013, as compared to 97,755 Mcf of natural gas and 10,538 barrels of natural gas liquids in the third quarter of 2012. The average price received in the third quarter of 2013 for natural gas and natural gas liquids sold from the San Juan Basin Royalty Properties located in the State of New Mexico was $2.89 per Mcf and $24.47 per barrel, respectively, compared to $1.83 per Mcf and $25.70 per barrel during the same period in 2012. Actual production volumes of natural gas attributable to the San Juan Basin properties located in the State of New Mexico increased to 189,811 Mcf in the third quarter of 2013 as compared to 183,656 Mcf of natural gas for the same period in 2012. Actual production volumes of natural gas liquids attributable to the San Juan Basin properties located in the State of New Mexico decreased to 21,098 barrels in the third quarter of 2013 compared to 23,086 barrels for the same period in 2012.

Capital expenditures on these properties were $188,885 in the third quarter of 2013, an increase of approximately 59% as compared to $118,432 in the third quarter of 2012 primarily due to increased developmental drilling costs for certain wells. Operating costs were $339,666 in the third quarter 2013, an increase of approximately 24% as compared to $274,753 in the third quarter of 2012. The increase in operating costs was primarily due to plugging costs incurred related to certain wells.

The Trust's interest in the San Juan Basin was conveyed from PNR's working interest in 31,328 net producing acres in northwestern New Mexico and southwestern Colorado. Substantially all of the natural gas produced from the San Juan Basin is currently being sold on the spot market.

Royalty income from the San Juan Basin Colorado Royalty Properties was $226,986 during the third quarter of 2013, compared to $37,752 during the third quarter of 2012. The increase in Royalty income was due primarily to higher natural gas prices and lower operating costs in the third quarter of 2013 offset in part by decreased natural gas production in the third quarter of 2013 compared to the third quarter of 2012. Net production attributable to the San Juan Basin Royalty Properties located in Colorado was 83,173 Mcf of natural gas during the third quarter of 2013 with 30,119 Mcf of natural gas attributable to the Trust during the third quarter of 2012. The average price received in the third quarter of 2013 for natural gas sold from the San Juan Basin Colorado Properties was $2.73, as compared to average price of $1.25 for the third quarter of 2012. Actual production volumes attributable to the San Juan Basin Colorado Properties decreased to 47,366 Mcf of natural gas in the third quarter of 2013 as compared to 55,544 Mcf of natural gas for the same period in 2012. Royalty income reported from BP is net of pre-main line production costs. These costs were charged to the Trust in error and as a result the Royalty income for previous periods was reduced. Because Royalty income recorded for a month is the amount computed and paid by BP, the additional Royalties, if any, will not be recorded until received by the Trust.

Operating costs on these properties were $(97,993) in the third quarter of 2013, as compared to $32,804 in the third quarter of 2012. The decrease in operating costs was due primarily to a cost and transportation credit of $117,450 in the third quarter of 2013 from BP.

Nine Months Ended September 30, 2013 and 2012

Financial Review

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Royalty income	$ 2,646,517	$ 2,926,291
Interest income	107	80,137
General and administrative expense	(123,360)	(235,424)
Distributable income	$ 2,523,264	$ 2,771,004
Distributable income per unit	$ 1.3540	$ 1.4869
Units outstanding	1,863,590	1,863,590

The Trust's Royalty income was $2,646,517 for the nine months ended September 30, 2013, a decrease of approximately 10% as compared to $2,926,291 for the nine months ended September 30, 2012, primarily as a result of lower natural gas and natural gas liquids production volumes, lower natural gas liquid prices and increased capital expenditures, offset in part by decreased operating costs and an increase in natural gas prices in the first nine months of 2013 as compared to the first nine months of 2012.

The distributable income of the Trust for each period includes the Royalty income received from the working interest owners during such period, plus interest income earned to the date of distribution. Trust administration expenses are deducted in the computation of distributable income. Distributable income for the nine months ended September 30, 2013 was $2,523,264, representing $1.3540 per unit, compared to $2,771,004, representing $1.4869, for the nine months ended September 30, 2012.

During 2011, the Trustee withheld $1.0 million for future unknown contingent liabilities and expenses in accordance with the Trust Indenture. As of September 30, 2013 the $1.0 million is included in cash and short-term investments.

Operational Review

Hugoton Field

Natural gas and natural gas liquids revenue from the Hugoton field attributable to the Royalty accounted for approximately 35% of the Royalty income of the Trust during the nine months ended September 30, 2013.

Royalty income attributable to the Hugoton Royalty Properties decreased to $936,686 for the nine months ended September 30, 2013 from $1,145,191 for the same period in 2012 primarily due to increased capital expenditures, lower prices for natural gas liquids and decreased natural gas production, offset in part by higher natural gas prices, increased natural gas liquids production and lower operating costs from the Hugoton Royalty Properties. The average price received in the first nine months of 2013 for natural gas and natural gas liquids sold from the Hugoton field was $3.80 per Mcf and $31.26 per barrel, respectively, compared to $3.03 per Mcf and $41.40 per barrel, respectively, during the same period in 2012. Net production attributable to the Hugoton Royalty Properties decreased to 151,304 Mcf of natural gas and 11,572 barrels of natural gas liquids for the nine months ended September 30, 2013 as compared to 214,302 Mcf of natural gas and 11,977 barrels of natural gas liquids for the nine months ended September 30, 2012. Actual production volumes attributable to the Hugoton Royalty Properties decreased to 337,592 Mcf of natural gas and increased to 25,102 barrels of natural gas liquids in the nine months ended September 30, 2013 as compared to 397,149 Mcf of natural gas and 22,367 barrels of natural gas liquids for the same period in 2012. The decrease in actual natural gas production is a result of natural production decline. The increase in actual natural gas liquids production is due to an increase in NGL yields.

Capital expenditures on these properties were $207,382 during the nine months ended September 30, 2013, an increase of approximately 3,235% as compared to $6,219 during the nine months ended September 30, 2012 primarily due to increased developmental drilling costs for certain wells. Operating costs were $923,327 during the nine months ended September 30, 2013, a decrease of approximately 5% as compared to $976,900 during the nine months ended September 30, 2012.

San Juan Basin

Royalty income from the San Juan Basin New Mexico was $1,270,229 for the first nine months of 2013 compared to $1,558,031 in the first nine months of 2012. The decrease in Royalty income was due primarily to increased capital expenditures and operating costs, lower natural gas liquids prices and lower natural gas liquids production volumes, offset in part by higher natural gas prices and higher natural gas production volumes from the San Juan Basin properties in the first nine months of 2013 compared to the first nine months of 2012. The average price received in the nine months ended September 30, 2013 for natural gas and natural gas liquids sold from the San Juan Basin Royalty Properties located in the state of New Mexico was $2.79 per Mcf and $25.46 per barrel, respectively, compared to $1.98 per Mcf and $30.46 per barrel, respectively, during the same period in 2012. Net production attributable to the San Juan Basin Royalty located in New Mexico was 229,223 Mcf of natural gas and 24,769 barrels of natural gas liquids for the nine months ended September 30, 2013 as compared to 267,042 Mcf of natural gas and 33,783 barrels of natural gas liquids for the nine months ended September 30, 2012. Actual production volumes attributable to the San Juan Basin Royalty Properties increased to 525,714 Mcf of natural gas and decreased to 65,671 barrels of natural gas liquids in the nine months ended September 30, 2013 as compared to 521,679 Mcf of natural gas and 70,058 barrels of natural gas liquids for the same period in 2012.

San Juan New Mexico capital expenditures were $638,735 during the nine months ended September 30, 2013, an increase of approximately 4% as compared to $612,141 during the nine months ended September 30, 2012. Operating costs were $990,515 during the nine months ended September 30, 2013, an increase of approximately 6% as compared to $938,249 during the nine months ended September 30, 2012.

Royalty income from the San Juan Basin Colorado Royalty Properties was $439,602 for the nine months ended September 30, 2013, compared to $223,069 during the same period in 2012. The increase in Royalty income was primarily the result of higher natural gas prices and decreased operating costs in the nine months ended September 30, 2013 compared to the same period in 2012. Net production attributable to the San Juan Basin Royalty Properties located in Colorado was 174,350 Mcf of natural gas during the nine months ended September 30, 2013 with 126,631 Mcf of natural gas attributable to the Trust during the same period in 2012. The average price received for the nine months ended September 30, 2013 for natural gas sold from the San Juan Basin Colorado Properties was $2.52, compared to $1.76 received during the same period in 2012. Actual production volumes attributable to the San Juan Basin Colorado Properties decreased to 161,433 Mcf of natural gas for the nine months ended September 30, 2013 as compared to 162,664 Mcf of natural gas for the same period in 2012.

Operating costs on these properties were $(31,698) for the nine months ended September 30, 2013, a decrease of approximately 151% as compared to $62,469 in the same period in 2012 due primarily to a cost and transportation credit received during the third quarter of 2013.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

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

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

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

Item 4. 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.

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" in the Trust's Annual Report on Form 10-K for the year ended December 31, 2012 for a description of certain risks relating to these arrangements and reliance, including filings such as this filing outside the time periods specified notwithstanding effective disclosure controls and procedures of the Trustee regarding information under its control.

The officer acting on behalf of the Trustee has not conducted a separate evaluation of the disclosure controls and procedures with respect to information furnished by the working interest owners. The Trustee notes that it is conducting an ongoing review of certain information and calculations by the working interest owners, along with an outside joint venture auditor. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources" under Item 7 on Form 10-K for the year ended December 31, 2012 for information concerning controls and procedures with respect to the Royalty.

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 II OTHER INFORMATION

Item 1. Legal Proceedings.

There are no pending legal proceedings to which the Trust is a named party. The Trustee has been advised by PNR, ConocoPhillips and BP Amoco that it is subject to litigation in the ordinary course of business for certain matters that include the Royalty Properties. While each of the working interest owners has advised the Trustee that it does not currently believe any of the pending litigation will have a material adverse effect net to the Trust, in the event such matters were adjudicated or settled in a material amount and charges were made against Royalty income, such charges could have a material impact of future Royalty income.

Item 1A. Risk Factors.

There have not been any material changes from risk factors previously disclosed in Item 1A to Part 1 of the Trust's Annual Report on Form 10-K for the year ended December 31, 2012.

Item 6. Exhibits.

(Asterisk indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. The Bank of New York Mellon Trust Company, N.A. is the successor trustee to JPMorgan Chase Bank, N.A. JPMorgan Chase Bank, N.A. was formerly known as The Chase Manhattan Bank and was successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association).

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

SIGNATURES

Pursuant to the requirements 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., as Trustee

By: /s/ MIKE ULRICH

Mike Ulrich
Vice President

Date: November 12, 2013

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

QuickLinks