MESA ROYALTY TRUST/TX
Form 10-Q
November 09, 2007

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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, 2007

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: 1-07884

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

Large accelerated filer o Accelerated filer ý Non-accelerated filer 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

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date. As of November 9, 2007 1,863,590 Units of Beneficial Interest 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,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
Royalty income	$ 3,180,214	$ 2,022,637	$ 8,406,218	$ 8,075,874
Interest income	24,883	5,099	69,374	19,441
General and administrative expense	(18,062)	(18,131)	(64,904)	(56,564)
Distributable income	$ 3,187,035	$ 2,009,605	$ 8,410,688	$ 8,038,751
Distributable income per unit	$ 1.7102	$ 1.0784	$ 4.5132	$ 4.3136
Units outstanding	1,863,590	1,863,590	1,863,590	1,863,590

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	September 30, 2007	December 31, 2006
	(Unaudited)	
ASSETS		
Cash and short-term investments	$ 3,155,573	$ 1,725,732
Interest receivable	31,462	6,551
Net overriding royalty interest in oil and gas properties	42,498,034	42,498,034
Accumulated amortization	(34,660,302)	(34,395,319)
Total assets	$ 11,024,767	$ 9,834,998
LIABILITIES AND TRUST CORPUS		
Distributions payable	$ 3,187,035	$ 1,732,283
Trust corpus (1,863,590 units of beneficial interest authorized and outstanding)	7,837,732	8,102,715
Total liabilities and trust corpus	$ 11,024,767	$ 9,834,998

(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,	
	2007	2006	2007	2006
Trust corpus, beginning of period	$ 7,910,943	$ 8,312,437	$ 8,102,715	$ 8,521,268
Distributable income	3,187,035	2,009,605	8,410,688	8,038,751
Distributions to unitholders	(3,187,035)	(2,009,605)	(8,410,688)	(8,038,751)
Amortization of net overriding royalty interest	(73,211)	(104,865)	(264,983)	(313,696)
Trust corpus, end of period	$ 7,837,732	$ 8,207,572	$ 7,837,732	$ 8,207,572

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

MESA ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS
(Unaudited)

Note 1 Trust Organization

The Mesa Royalty Trust (the "Trust") was created on November 1, 1979 when Mesa Petroleum Co. conveyed to the Trust a 90% net profits overriding royalty interest (the "Royalty") in certain producing oil and gas properties located in the Hugoton field of Kansas, the San Juan Basin field of New Mexico and Colorado and the Yellow Creek field of Wyoming (collectively, the "Royalty Properties"). Mesa Petroleum Co. was the predecessor to Mesa Limited Partnership ("MLP"), the predecessor to MESA Inc. On April 30, 1991, MLP sold its interests in the Royalty Properties located in the San Juan Basin field to ConocoPhillips (successor by merger to Conoco, Inc.). ConocoPhillips sold most of its interests in the San Juan Basin Royalty Properties located in Colorado to MarkWest Energy Partners, Ltd. (effective January 1, 1993) and Red Willow Production Company (effective April 1, 1992). On October 26, 1994, MarkWest Energy Partners, Ltd. sold substantially all of its interest in the Colorado San Juan Basin Royalty Properties to BP Amoco Company ("BP"), a subsidiary of BP p.l.c. Until August 7, 1997, MESA Inc. operated the Hugoton Royalty Properties through Mesa Operating Co., a wholly owned subsidiary of MESA Inc. On August 7, 1997, MESA Inc. merged with and into Pioneer Natural Resources Company ("Pioneer"), formerly a wholly owned subsidiary of MESA Inc., and Parker & Parsley Petroleum Company merged with and into Pioneer Natural Resources USA, Inc. (successor to Mesa Operating Co.), a wholly owned subsidiary of Pioneer ("PNR") (collectively, the mergers are referred to herein as the "Merger"). Subsequent to the Merger, the Hugoton Royalty Properties have been operated by PNR. All of the San Juan Basin Royalty Properties located in New Mexico and a few wells located in Southwest Colorado near the New Mexico border, are operated by ConocoPhillips. Substantially all of the San Juan Basin Royalty Properties located in Colorado are operated by BP. As used in this report, PNR refers to the operator of the Hugoton Royalty Properties, ConocoPhillips refers to the operator of the San Juan Basin Royalty Properties, other than the portion of such properties located in Colorado, and BP refers to the operator of the Colorado San Juan Basin Royalty Properties unless otherwise indicated. The terms "working interest owner" and "working interest owners" generally refer to the operators of the Royalty Properties as described above, unless the context in which such terms are used indicates otherwise.

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

Note 2 Basis of Presentation

The accompanying unaudited financial information has been prepared by The Bank of New York Trust Company, N.A. ("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 periods. 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, 2006.

In accordance with the instruments conveying the Royalty, the Working Interest Owners will calculate and pay the Trust each month an amount equal to 90% of the net proceeds for the preceeding month. The Trust Indenture was amended in 1985, the effect of which was an overall reduction of approximately 88.56% in the size of the Trust; therefore, the Trust is now entitled to receive 90% of 11.44% of the net proceeds for the preceding month. Generally, net proceeds means the excess of the amounts received by the Working Interest Owners from sales of oil and gas from the Royalty Properties over operating and capital costs incurred.

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 accrue;

(d) Amortization of the net overriding royalty interests, which is calculated on a unit-of-production basis, 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 other day as the Trustee determines is required to comply with legal 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 thought to be the most meaningful because distributions to the unitholders for a month are based on net cash receipts for such month. However, it will differ from the basis used for financial statements prepared in accordance with accounting principles accepted in the United States of America because under these accounting principles, royalty income for a month would be based on net proceeds from production for such month without regard to when calculated or received and interest income for a month would be calculated only through the end of such month.

Note 3 Legal Proceedings

There are no pending legal proceedings to which the Trust is a named party. PNR has advised the Trustee that the previously reached 2006 settlement in the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.,* filed in the 26th Judicial District Court, Stevens County, Kansas, was approved in the first quarter of 2007 by the Judge and the case was finalized in April 2007. The plaintiffs in the above noted lawsuit were royalty owners in oil and gas properties located in the Hugoton field, which are owned by Pioneer USA, a subsidiary of Pioneer Natural Resources Company ("Pioneer"). The plaintiffs sued a predecessor company to Pioneer USA asserting various claims relating to alleged improper deductions in the calculation of royalties.

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

Pioneer's portion of the cash payment is approximately $32,700,000. Pioneer agreed to pay the cash portion in two installments. Pioneer advised the Trustee that the portion of the cash payments net to the Trust's interest was approximately $1,000,000 paid on September 30, 2006 and an expected payment of approximately $900,000 payable on September 30, 2007. The approximate $1,000,000 attributable to the Trust paid on September 30, 2006, was deducted from royalty income in the fourth quarter of 2006. In October 2007, Pioneer informed the Trustee that during the course of Pioneer USA's analysis of the payments under the terms of the settlement agreement, Pioneer USA has now determined that the Trust should not bear any portion of the second installment payment and that Pioneer USA should reimburse the Trust for the portion of the first installment payment previously charged to the Trust and paid in September 2006. As a result, Pioneer USA included a reimbursement of $1,096,630, including interest in the amount of $110,492, to the distribution made to the Trust in October 2007 to be included in the Trust's fourth quarter receipts, and no portion of the second installment payment will be charged to the Trust.

Note 4 Federal 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 will incur no federal income tax liability.

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 7 to the financial statements in the Trust's Annual Report on Form 10-K for the year ended December 31, 2006. 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 have been 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, 2006, including under Part I, "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 AND AVERAGE PRICES

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 Royalty conveyance. The following unaudited summary illustrates the net effect of the components of the actual Royalty computation for the periods indicated:

	Three Months Ended September 30,			
	2007		2006	
	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)	$ 3,034,288	$ 1,212,004	$ 2,446,591	$ 961,060
Less the Trust's proportionate share of:				
Capital costs recovered(2)	(131,706)	(51,951)	(312,767)	
Operating costs	(641,806)	(240,615)	(950,360)	(64,977)
Withheld revenues(3)			(56,910)	
Royalty income	$ 2,260,776	$ 919,438	$ 1,126,554	$ 896,083
Average sales price	$ 5.95	$ 42.54	$ 5.50	$ 42.12
	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Net production volumes attributable to the Royalty(4)	377,403	21,658	204,854	21,276

	Nine Months Ended September 30,			
	2007		2006	
	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)	$ 8,411,487	$ 3,133,703	$ 9,847,458	$ 2,736,377
Less the Trust's proportionate share of:				
Capital costs recovered(2)	(709,147)	(51,951)	(845,399)	
Operating costs	(2,007,776)	(370,098)	(2,931,776)	(212,542)
Withheld revenues(3)			(518,244)	
Royalty income	$ 5,694,564	$ 2,711,654	$ 5,552,039	$ 2,523,835
Average sales price	$ 5.84	$ 38.09	$ 7.40	$ 41.03
	(Mcf)	(Bbls)	(Mcf)	(Bbls)
Net production volumes attributable to the Royalty(4)	970,988	71,823	750,106	61,507

(1)

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

(2)

Capital costs recovered represents capital costs incurred during the current or prior periods to the extent that such costs have been recovered by the working interest owners from current period Gross Proceeds.

(3)

The Colorado portion of the San Juan Basin Royalty properties recouped all costs related to the Fruitland Coal drilling program as of December 2004. However, subsequent cumulative earnings were not remitted to the Trust until December 2006 and July 2007. The cumulative earnings reported to the Trust by the Working Interest Owner from January 2005 through October 2006 totaled approximately $1,280,000. In December 2006, BP as operator of a portion of the San Juan Basin-Colorado Royalty properties remitted approximately

$978,000 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings. In the quarter ended September 30, 2007, Red Willow remitted $226,000 to the Trust relating to San Juan Basin-Colorado Royalty properties that it operates. Of the $226,000 remitted by Red Willow, $19,000 and $66,000 relates to production during the three and nine months ended September 30, 2007, respectively. The remaining $159,000 relate to undistributed earnings from January 2005 through December 2006. Since Royalty income for the Trust is recorded on a cash basis, Royalty income for the three and nine months ended September 30, 2006 was not recognized until the quarters ended December 31, 2006 and September 30, 2007.

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 royalty income for previous periods were 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, which is anticipated to be January 2008.

(4)

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

Three Months Ended September 30, 2007 and 2006

	Three Months Ended September 30,	
	2007	**2006**
Royalty income	$ 3,180,214	$ 2,022,637
Interest income	24,883	5,099
General and administrative expense	(18,062)	(18,131)
Distributable income	$ 3,187,035	$ 2,009,605
Distributable income per unit	$ 1.7102	$ 1.0784
Units outstanding	1,863,590	1,863,590

The Trust's Royalty income was $3,180,214 in the third quarter of 2007, an increase of approximately 57% as compared to $2,022,637 in the third quarter of 2006, primarily as a result of increased royalty income from the San Juan Basin properties, higher natural gas prices, higher natural gas liquids production, as well as, a decrease in capital spending in the third quarter of 2007 as compared to the third quarter of 2006.

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 quarter ended September 30, 2007 was $3,187,035, representing $1.7102 per unit, compared to $2,009,605, representing $1.0784 per unit, for the quarter ended September 30, 2006.

Based on 1,863,590 units outstanding for the quarters ended September 30, 2007 and 2006, respectively, the per unit distributions were as follows:

	2007	2006
July	$ 0.6174	$ 0.3524
August	0.5919	0.3503
September	0.5009	0.3757
	$ 1.7102	$ 1.0784

Hugoton Field

Natural gas and natural gas liquids production attributable to the Royalty from the Hugoton field accounted for approximately 39% of the Royalty income of the Trust during the third quarter of 2007.

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 recently including Greely Gas and Oneok Gas Marketing, Inc. PNR has advised the Trust that it expects to continue to market gas production from the Hugoton field under short-term and multi-month contracts. Overall market prices received for natural gas from the Hugoton Royalty Properties were higher in the third quarter of 2007 compared to the third quarter of 2006.

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 been renewed on a year-to-year basis since June 1, 2001. PNR extended the contract through June 1, 2008. Pursuant to the Gas Transportation Agreement, WRI has agreed to compress and transport up to 160 MMcf per day of gas and redeliver such gas to PNR at the inlet of PNR's Satanta Plant. PNR agreed to pay WRI a fee of $0.06 per Mcf escalating 4% annually as of June 1, 1996. This Gas Transportation Agreement has been assigned to Kansas Gas Service ("Oneok").

Royalty income attributable to the Hugoton Royalty Properties increased to $1,237,354 in the third quarter of 2007, as compared to $1,127,867 in the third quarter of 2006 primarily due to an increase in overall prices received from the Hugoton Royalty Properties as well as an increase in gas production. The average price received in the third quarter of 2007 for natural gas and natural gas liquids sold from the Hugoton Royalty Properties was $6.66 per Mcf and $46.86 per barrel, respectively, compared to $5.67 per Mcf and $41.17 per barrel during the same period in 2006. Net production attributable to the Hugoton Royalty was 135,835 Mcf of natural gas and 6,639 barrels of natural gas liquids in the third quarter of 2007 compared to 123,530 Mcf of natural gas and 10,383 barrels of natural gas liquids in the third quarter of 2006. Actual production volumes attributable to the Hugoton properties increased to 188,313 Mcf of natural gas and decreased to 9,210 barrels of natural gas liquids in the third quarter of 2007 as compared to 178,166 Mcf of natural gas and 10,389 barrels of natural gas liquids for the same period in 2006 as a result of new equipment to reduce field fuel usage thus increasing overall production.

The Trustee has been advised that beginning July 1, 2007, the Hugoton and Panoma fields will be considered a single, common source of supply and will operate under a single combined Basic Proration Order (BPO). After July 1, 2007, the wells in each of these fields will be allowed to produce at their open flow potential and will no longer be subject to allowable restrictions. Also if no objection is received by December 31, 2007, any and all overage or underage that a well may have accrued will be cancelled.

Capital expenditures on these properties were $36,117 in the third quarter of 2007, as compared to $13,280 in the third quarter of 2006. Operating costs were $431,634 in the third quarter of 2007, an increase of approximately 46% as compared to $295,646 in the third quarter of 2006. The increase in operating expenses between the three months ended September 30, 2006 and the three months ended September 30, 2007 is due to increased production taxes, well workovers, and higher rates charged by service providers.

San Juan Basin

Royalty income from the San Juan Basin Royalty Properties is calculated and paid to the Trust on a state-by-state basis. Substantially all of the Royalty income from the San Juan Basin Royalty Properties are located in the State of New Mexico. Royalty income from the San Juan Basin Royalty Properties located in the state of New Mexico was $1,586,626 during the third quarter of 2007 as compared with $894,770 in the third quarter of 2006. The increase was primarily due to higher natural gas and natural gas liquids production and decreased capital expenses and operating expenses in the third quarter of 2007. The average price received in the third quarter of 2007 for natural gas sold from the San Juan Basin Royalty Properties was $5.59 per Mcf and $40.41 per barrel, respectively, compared to $5.24 per Mcf and $43.02 per barrel during the same period in 2006. Net production attributable to the San Juan Basin Royalty was 175,530 Mcf of natural gas and 15,019 barrels of natural gas liquids in the third quarter of 2007 as compared to 81,324 Mcf of natural gas and 10,893 barrels of natural gas liquids in the third quarter of 2006. Actual production volumes attributable to the San Juan Basin properties increased to 249,146 Mcf of natural gas and 20,196 barrels of natural gas liquids in the third quarter of 2007 as compared to 236,843 Mcf of natural gas and 12,404 barrels of natural gas liquids for the same period in 2006. The increase in actual production volume for the three month period ended September 30, 2007 compared to the same period in 2006 was due to the better run times on conventional gathering.

Capital expenditures on these properties were $147,540 in the third quarter of 2007, a decrease of 51% as compared to $299,487 in the third quarter of 2006 due to a decrease in capital facilities spending. Operating costs were $399,268 in the third quarter of 2007, a decrease of approximately 31% as compared to $580,448 in the third quarter of 2006. The decrease in operating expenses for the three month period ended September 30, 2007 compared to the same period in 2006 was due to a reduction in facilities expense and a reduction in well workover expenses.

The Trust's interest in the San Juan Basin was conveyed from PNR's working interest in 31,328 net producing acres in northwestern New Mexico and southwestern Colorado.

The costs related to the San Juan Basin, Colorado portion were recovered in December 2004. However, subsequent earnings were not remitted to the Trust until December 2006 and July 2007. The cumulative earnings, including interest on undistributed earnings, reported to the Trust by the Working Interest Owner through November 2006, totaled $1,280,412. In December 2006, BP remitted $978,349 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings for the San Juan properties it operates. In July 2007, Red Willow remitted $159,497 for payment of undistributed earnings from January 2005 through December 2006 for the properties it operates. BP communicated to the Trust these distributions represent all of the previously unpaid revenues. The Trustee is currently investigating the $142,566 difference in the original estimate of unpaid proceeds of $1,280,412 and the payments of $1,137,846. Since Royalty income for the Trust is recorded on a cash basis, the third quarter 2006 earnings were not recognized as income until the quarters ended December 31, 2006 and September 30, 2006.

Royalty income from the San Juan Basin Colorado Royalty Properties was $356,234 during the third quarter of 2007, compared to none received during the third quarter of 2006. Royalty income received in the current quarter from Red Willow operated properties relating to undistributed earnings from prior periods totaled $206,836. The operators did not pay the Trust amounts received during the third quarter of 2006, as discussed above. Net production attributable to the San Juan Basin Royalty Properties located in Colorado was 66,038 Mcf of natural gas during the third quarter of 2007 with no volumes attributable to the Trust during the third quarter of 2006. The average price received in the third quarter of 2007 for natural gas sold from the San Juan Basin Colorado Properties was $5.39. Actual production volumes attributable to the San Juan Basin Colorado Properties increased to 75,652 Mcf of natural gas in the third quarter of 2007 as compared to 45,818 Mcf of natural gas for the same period in 2006. 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 royalty income for previous periods were 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, which is anticipated to be January 2008.

Operating costs on these properties were $51,519 in the third quarter of 2007, a decrease of approximately 63% as compared to $139,243 in the third quarter of 2006 attributed to a decrease in maintenance work and lease operating expenses (labor, fuel, electricity, and chemicals).

Nine Months Ended September 30, 2007 and 2006

	Nine Months Ended September 30,	
	2007	**2006**
Royalty income	$ 8,406,218	$ 8,075,874
Interest income	69,374	19,441
General and administrative expense	(64,904)	(56,564)
Distributable income	$ 8,410,688	$ 8,038,751
Distributable income per unit	$ 4.5132	$ 4.3136
Units outstanding	1,863,590	1,863,590

The Trust's Royalty income was $8,406,218 for the nine months ended September 30, 2007, an increase of approximately 4% as compared to $8,075,874 for the nine months ended September 30, 2006, primarily as a result of increased royalty income from the San Juan Basin properties and an overall decrease in capital expenditures in the first nine months of 2007 as compared to the first nine months of 2006.

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, 2007 was $8,410,688, representing $4.5132 per unit, compared to $8,038,751, representing $4.3136 per unit, for the nine months ended September 30, 2006.

Hugoton Field

Royalty income attributable to the Hugoton Royalty Properties decreased to $3,569,852 for the nine months ended September 30, 2007 from $4,599,630 for the same period in 2006, due to decreases in natural gas and natural gas liquids price from the Hugoton Royalty Properties and decreases in natural gas liquids production. The average price received in the first nine months of 2007 for natural gas and natural gas liquids sold from the Hugoton field was $6.30 per Mcf and $40.65 per barrel, compared to $7.99 per Mcf and $41.60 per barrel during the same period in 2006. Net production attributable to the Hugoton Royalty Properties decreased to 406,791 Mcf of natural gas and 24,701 barrels of natural gas liquids for the nine months ended September 30, 2007 as compared to 413,228 Mcf of natural gas and 31,200 barrels of natural gas liquids for the nine months ended September 30, 2006. Actual production volumes attributable to the Hugoton Royalty Properties increased to 565,612 Mcf of natural gas and decreased to 27,281 barrels of natural gas liquids for the nine months ended September 30, 2007 as compared to 550,494 Mcf of natural gas and 31,220 barrels of natural gas liquids for the same period in 2006. The increase in gas production and the decrease in the natural gas liquids production for the nine month period ended September 30, 2007 compared to the same period in 2006 was primarily due to the fact that the nitrogen rejection unit was down for a portion of January and February in 2007. The shut-down of the nitrogen rejection unit increased the gas production while it decreased the natural gas liquids production.

The Hugoton capital expenditures were $51,995 during the nine months ended September 30, 2007, a decrease of approximately 69% as compared to $167,048 during the nine months ended September 30, 2006. The decrease in the capital expenditures was primarily due to less wells drilled in 2007. Operating costs were $1,066,040 during the nine months ended September 30, 2007, an increase of approximately 15% as compared to $929,297 during the nine months ended September 30, 2006 due to increases in ad valorem taxes and well workovers.

San Juan Basin

Royalty income from the San Juan Basin Royalty Properties is calculated and paid to the Trust on a state-by-state basis. Substantially all of the Royalty income from the San Juan Basin Royalty Properties are located in the state of New Mexico. The San Juan-New Mexico Royalty income was $4,098,811 for the first nine months of 2007 compared to $3,476,244 in the first nine months of 2006. The increase in Royalty income was due primarily to increased natural gas liquid production and decreased operating expenditures in the first nine months of 2006 from the San Juan Basin-New Mexico properties. Net production attributable to the San Juan-New Mexico properties increased to 420,338 Mcf of natural gas and 47,122 barrels of natural gas liquids for the nine months ended September 30, 2007 as compared to 336,878 Mcf of natural gas and 30,307 barrels of natural gas liquids for the nine months ended September 30, 2006. Actual production volumes attributable to the San Juan-New Mexico properties increased to 716,324 Mcf of natural gas and 56,559 barrels of natural gas liquids in the nine months ended September 30, 2007 as compared to 700,915 Mcf of natural gas and 35,565 barrels of natural gas liquids for the same period in 2006. The increase in production volume for the nine month period ended September 30, 2007 compared to the same period 2006 was due to the better run times on conventional gathering. The average price received in the nine months ended

September 30, 2007 for natural gas and natural gas liquids sold from the San Juan-New Mexico properties was $6.38 per Mcf and $43.49 per barrel, respectively, compared to $6.68 per Mcf and $40.45 per barrel during the same period in 2006.

San Juan-New Mexico capital expenditures were $709,103 during the nine months ended September 30, 2007, an increase of approximately 5% as compared to $678,351 during the nine months ended September 30, 2006. Operating costs were $1,226,650 during the nine months ended September 30, 2007, a decrease of approximately 38% as compared to $1,966,468 during the nine months ended September 30, 2006. The decrease in operating costs during the nine month period ended September 30, 2007 compared to the same period in 2006 was due to inclement weather that impacted the operations coupled with a reduction in lease inspections, facilities expenses and well workover expenses.

The costs related to the San Juan Basin, Colorado portion were recovered in December 2004. However, subsequent earnings were not remitted to the Trust until December 2006 and July 2007. The cumulative earnings, including interest on undistributed earnings, reported to the Trust by the working interest owner through November 2006, totaled $1,280,412. In December 2006, BP remitted $978,349 for payment of undistributed earnings from January 2005 through October 2006 and November 2006 earnings related to the properties it operates. In July 2007, Red Willow remitted $159,497 for payment of undistributed earnings from January 2005 through December 2006 for the San Juan Basin-Colorado Royalty properties it operates. BP communicated to the Trust these distributions represent all of the previously unpaid revenues. The Trustee is currently investigating the $142,566 difference in the original estimate of unpaid proceeds of $1,280,412 and the payment of $1,137,846. Since Royalty income for the Trust is recorded on a cash basis, the earnings for the nine months ended September 30, 2006 were not recognized as income until the quarter ended December 31, 2006 and September 30, 2007.

Royalty income from the San Juan Basin Colorado Royalty Properties was $737,555 for the nine months ended September 30, 2007, compared to none received during the same period in 2006 Royalty income received in the nine months ended September 30, 2007 from Red Willow operated properties relating to undistributed earnings from prior periods totaled $159,497. The operators did not pay to the Trust amounts received during the first nine months of 2006. Net production attributable to the San Juan Basin Royalty Properties located in Colorado was 143,859 Mcf of natural gas during the nine months ended September 30, 2007 with no volumes attributable to the Trust during the same period in 2006. The average price received for the nine months ended September 30, 2007 for natural gas sold from the San Juan Basin Colorado Properties was $5.13. Actual production volumes attributable to the San Juan Basin Colorado Properties increased to 160,265 Mcf of natural gas for the nine months ended September 30, 2007 as compared to 89,959 Mcf of natural gas for the same period in 2006. Royalty income reported from BP during the nine months ended September 30, 2007, is net of pre-main line production costs. These costs were charged to the Trust in error and as a result royalty income for previous periods were 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, which is anticipated to be January 2008.

Operating costs on these properties were $85,184 for the nine months ended September 30, 2007, a decrease of approximately 66% as compared to $248,553 in the same period in 2006 attributed to a decrease in maintenance work and lease operating expenses (labor, fuel, electricity, and chemicals).

Item 3. ***Quantitative and Qualitative Disclosures About Market Risk.***

The Trust does not utilize market risk sensitive instruments. However, see the discussion of marketing by the working interest owners above.

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 (the "Exchange Act"), is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, 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 Trust Company, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosure.

As of the end of the period covered by this report, the Trustee carried out an evaluation of the Trustee's disclosure controls and procedures. Mike Ulrich, as Vice President of the Trustee, has concluded that these controls and procedures were effective at that time.

Due to the contractual arrangements of (i) the Trust Indenture and (ii) the rights of the Partnership 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 None of the Trustee or its unitholders control the operation or development of the Royalty Properties and have little influence over operation or development" and " The Trustee relies upon the working interests owners for information regarding the Royalty Properties" in the Trust's Annual Report on Form 10-K for the year ended December 31, 2006 for a description of certain risks relating to these arrangements and reliance.

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. PNR has advised the Trustee that the previously reached 2006 settlement in the lawsuit *John Steven Alford and Robert Larrabee, individually and on behalf of a Plaintiff Class v. Pioneer Natural Resources USA, Inc.,* filed in the 26th Judicial District Court, Stevens County, Kansas, was approved in the first quarter of 2007 by the Judge and the case was finalized in April 2007. The plaintiffs in the above noted lawsuit were royalty owners in oil and gas properties located in the Hugoton field, which are owned by Pioneer USA, a subsidiary of Pioneer Natural Resources Company ("Pioneer"). The plaintiffs sued a predecessor company to Pioneer USA asserting various claims relating to alleged improper deductions in the calculation of royalties.

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

As noted in prior disclosures, Pioneer's portion of the cash payment is approximately $32,700,000. Pioneer agreed to pay the cash portion in two installments. Pioneer has advised the Trustee that the portion of the cash payments net to the Trust's interest was approximately $1,000,000 paid on September 30, 2006 and an expected payment of approximately $900,000 payable on September 30, 2007. The approximate $1,000,000 attributable to the Trust paid on September 30, 2006, was deducted from royalty income in the fourth quarter of 2006.

In October 2007, Pioneer informed the Trustee that during the course of Pioneer USA's analysis of the payments under the terms of the settlement agreement, Pioneer USA has now determined that the Trust should not bear any portion of the second installment payment and that Pioneer USA should reimburse the Trust for the portion of the first installment payment previously charged to the Trust and paid in September 2006. As a result, Pioneer USA included a reimbursement of $1,096,630, including interest in the amount of $110,492, to the distribution made to the Trust in October 2007, and no portion of the second installment payment will be charged to the Trust.

Item 1A. ***Risk Factors.***

There have not been any material changes from risk factors previously disclosed in response to Item 1A. to Part 1 of the Trust's Form 10-K for the year ended December 31, 2006.

Item 6. ***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 from JPMorgan Chase Bank, N.A. effective in October 2006. 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)	1-07884	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)	1-07884	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)	1-07884	4(e)
31	Rule 13a-14(a)/15d-14(a) Certification		
32	Section 1350 Certification		

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 Trust Company, N.A., as Trustee

By: ______________________________

Mike Ulrich
Vice President

Date: November 9, 2007

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

QuickLinks