

```
*****
* IMPORTANT: Please note the information in the submission header MUST match the information *
* on the cover page of your filing. The SEC accepts or suspends filings based upon the *
* information in the submission header. Please carefully check all tags and values, *
* as well as the content of your EDGAR proof. *
*
* REGISTRANT TRANSMISSION AUTHORIZATION *
*
* [ ] I have reviewed the submission header and find it to be correct. *
* [ ] I have reviewed the submission file and find it to be correct and complete. *
* [ ] I have reviewed the electronic HTML proof and find all content including graphics and *
* links to be correct. *
* [ ] I authorize Merrill Corporation to transmit this filing to the SEC. *
*
* Printed Name: _____ Date: _____ Time: _____ *
*
* Signature: _____ *
*
*****
```

<SUBMISSION>
<TYPE> 10-K
<LIVE>
<DOCUMENT-COUNT> 5 (3 Edgar Docs, 2 Graphic Docs)
<FILER>
<CIK> 0000711303
<CCC> XXXXXXXXX
</FILER>
<SROS> NONE
<PERIOD> 12/31/2003
<SUBMISSION-CONTACT>
<NAME> EDGAR Advantage Service Team
<PHONE> (800) 688 - 1933
</SUBMISSION-CONTACT>

<DOCUMENT>

<TYPE> 10-K

<DESCRIPTION> 10-K

<FILENAME> a2131325z10-k.htm

<TEXT>

Use these links to rapidly review the document
[TABLE OF CONTENTS PART I](#)

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

FORM 10-K

(Mark One)

- ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2003**
- 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 1-8432

Mesa Offshore Trust

(Exact Name of Registrant as Specified in Its Charter)

Texas
(State or Other Jurisdiction of Incorporation or Organization)

76-6004065
(I.R.S. Employer Identification No.)

**JPMorgan Chase Bank, Trustee
Institutional Trust Services
700 Lavaca Austin, Texas**
(Address of Principal Executive Offices)

78701
(Zip Code)

Registrant's telephone number, including area code: 1-800-852-1422

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange On Which Registered
None	None

Securities registered pursuant to Section 12(g) of the Act:

Units of beneficial interest
(Title of Class)

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 No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes No

The aggregate market value of 71,980,216 Units of Beneficial Interest in Mesa Offshore Trust held by non-affiliates of the registrant at the closing sales price on June 30, 2003, of \$0.03 was approximately \$2,159,400.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

As of March 29, 2003, 71,980,216 Units of Beneficial Interest in Mesa Offshore Trust.

Documents Incorporated By Reference: None.

TABLE OF CONTENTS

PART I

	<u>Page</u>
Item 1. <u>Business</u>	1
<u>Description of the Trust</u>	1
<u>Description of the Units</u>	3
<u>Termination of the Trust</u>	5
<u>Description of Royalty Properties</u>	7
<u>Contracts</u>	13
<u>Regulation and Prices</u>	14
<u>Principal Trust Risk Factors</u>	16
Item 2. <u>Properties</u>	19
Item 3. <u>Legal Proceedings</u>	19
Item 4. <u>Submission of Matters to a Vote of Security Holders</u>	19

PART II

Item 5. <u>Market for the Registrant's Common Equity and Related Unitholder Matters</u>	20
Item 6. <u>Selected Financial Data</u>	20
Item 7. <u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	20
<u>Net Proceeds, Production and Average Prices (Unaudited)</u>	26
Item 7A. <u>Quantitative and Qualitative Disclosures About Market Risk</u>	28
Item 8. <u>Financial Statements and Supplementary Data</u>	28
Item 9. <u>Changes in and Disagreements with Accountants on Accounting and Financial Disclosure</u>	39
Item 9A. <u>Controls and Procedures</u>	39

PART III

Item 10. <u>Directors and Executive Officers of the Registrant</u>	40
Item 11. <u>Executive Compensation</u>	40
Item 12. <u>Security Ownership of Certain Beneficial Owners and Management</u>	40
Item 13. <u>Certain Relationships and Related Transactions</u>	41
Item 14. <u>Principal Accountant Fees and Services</u>	41

PART IV

Item 15. <u>Exhibits, Financial Statement Schedules and Reports on Form 8-K</u>	42
<u>SIGNATURES</u>	43

Note Regarding Forward-Looking Statements

This Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included in this Form 10-K, including without limitation the statements under "Business—Termination of the Trust," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 1 to the financial statements of the Trust regarding the future net revenues of the Trust, are forward-looking statements. Although Pioneer Natural Resources Company ("Pioneer") has advised the Trust that it believes that the expectations reflected in such forward-looking statements are reasonable, no assurance can be given that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from expectations ("Cautionary Statements") are disclosed in this Form 10-K, including, without limitation in conjunction with the forward-looking statements included in this Form 10-K. A consolidated summary description of principal risk factors that could cause actual results to differ is also set forth in this Form 10-K under "Business—Principal Trust 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.

PART I

Item 1. Business.

DESCRIPTION OF THE TRUST

The Mesa Offshore Trust (the "Trust"), created under the laws of the State of Texas, maintains its offices at the office of the Trustee, JPMorgan Chase Bank (the "Trustee"), 700 Lavaca, Austin, Texas 78701. The telephone number of the Trust is 1-800-852-1422. JPMorgan Chase Bank was formerly known as The Chase Manhattan Bank and is the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association.

The Trustee does not maintain a website for filings by the Trust with the U.S. Securities and Exchange Commission ("SEC"). Electronic filings by the Trust with the SEC are available free of charge through the SEC's website at www.sec.gov.

The principal asset of the Trust consists of a 99.99% interest in the Mesa Offshore Royalty Partnership (the "Partnership"). The Trust was created on December 28, 1982, effective December 1, 1982, when Mesa Petroleum Co. conveyed to the Partnership certain overriding royalty interests (collectively, the "Royalty") carved out of Mesa Petroleum Co.'s existing working interests in ten producing and non-producing oil and gas leases offshore Louisiana and Texas (the "Royalty Properties"). The Partnership was formed for the purpose of receiving and holding the Royalty, receiving the proceeds from the Royalty, paying the liabilities and expenses of the Partnership and disbursing remaining revenues to the Trustee and Mesa Offshore Management Co., the managing general partner of the Partnership at that time, in accordance with their interests. Until August 7, 1997, MESA Inc. owned and operated its assets through Mesa Operating Co. ("Mesa"), the operator and the managing general partner of the Royalty Properties. On August 7, 1997, MESA Inc. merged with and into 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, Pioneer owns and operates its assets through PNR and is also the managing general partner of the Partnership. As hereinafter used in this report, the term PNR generally refers to the operator of the Royalty Properties, unless otherwise indicated. See "Termination of the Trust" on page 5 of this Form 10-K for additional information regarding PNR and the Trust.

Units of beneficial interest ("units") in the Trust were issued on December 28, 1982 to Mesa Petroleum Co. shareholders, who received one unit for each share of Mesa Petroleum Co. common stock held.

The terms of the Mesa Offshore Trust Indenture (the "Trust Indenture") provide, among other things, that: (1) the Trust cannot acquire any asset other than its interest in the Partnership and cannot engage in any business or investment activity; (2) the Royalty can be sold in part or in total for cash upon approval of the unitholders or upon termination of the Trust; (3) the Trustee can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payment of the borrowing; (4) the Trustee will make quarterly distributions of cash available for distribution to the unitholders in January, April, July and October of each year; and (5) the Trust will terminate upon the first to occur of the following events: (i) the total amount of cash received per year by the Trust for each of three successive years commencing after December 31, 1987 is less than ten times one-third of the total amount payable to the Trustee as compensation for such three-year period (the "Termination Threshold") or (ii) a vote by holders of a majority of the outstanding units in favor of termination. Amounts paid to the Trustee as compensation were approximately \$152,000, \$84,000, and \$116,000, for the years 2003, 2002 and 2001, respectively. Upon termination of the Trust, the

Trustee will sell for cash all the assets held in the Trust estate and make a final distribution to unitholders of any funds remaining after all Trust liabilities have been satisfied.

The terms of the First Amended and Restated Articles of General Partnership of the Partnership (the "Partnership Agreement") provide that the Partnership shall dissolve upon the occurrence of any of the following: (1) December 31, 2030; (2) the election of the Trustee to dissolve the Partnership; (3) the termination of the Trust; (4) the bankruptcy of the Managing General Partner; or (5) the dissolution of the Managing General Partner or its election to dissolve the Partnership; provided that the Managing General Partner shall not elect to dissolve the Partnership so long as the Trustee remains the only other partner of the Partnership.

Under the instrument conveying the Royalty to the Partnership (the "Conveyance"), the Trust is entitled to its share (99.99%) of 90% of the Net Proceeds, as hereinafter defined, realized from the sale of the hydrocarbons as, if and when produced from the Royalty Properties. See "Description of Royalty Properties" on page 6 of this Form 10-K. The Conveyance provides for a monthly computation of Net Proceeds. "Net Proceeds" means the excess of Gross Proceeds, as hereinafter defined, received by PNR during a particular period over operating and capital costs and an amount to be recovered for future abandonment costs during such period. "Gross Proceeds" means generally the amount received by PNR from the sale of its share of minerals covered by the Royalty, subject to certain adjustments. Operating costs means, generally, costs incurred by PNR in operating the Royalty Properties, including capital costs. If operating and capital costs exceed the Gross Proceeds for any month, the excess plus interest thereon at the prime rate of the Bank of America plus one-half percent is recovered out of future Gross Proceeds prior to the making of further payment to the Trust. The Trust is not liable for any operating costs or other costs or liabilities attributable to the Royalty Properties or minerals produced therefrom. PNR, as owner of the working interest in the Royalty Properties, is required to maintain books and records sufficient to determine the amounts payable under the Royalty. Additionally, in the event of a controversy between PNR and any purchaser as to the correct sale price for any production, amounts received by PNR and promptly deposited by it with an escrow agent are not considered as having been received by PNR and therefore are not subject to being payable with respect to the Royalty until the controversy is resolved; but all amounts thereafter paid to PNR by the escrow agent will be considered amounts received from the sale of production. Similarly, operating costs include any amounts PNR is required to pay whether as a refund, interest or penalty to any purchaser because the amount initially received by PNR as the sales price was in excess of that permitted by the terms of any applicable contract, statute, regulation, order, decree or other obligation. Within 30 days following the close of each calendar quarter, PNR is required to deliver to the Trustee a statement of the computation of Net Proceeds attributable to such quarter.

The Royalty Properties are required to be operated by PNR in accordance with reasonable and prudent business judgment and good oil and gas field practices. PNR has the right to abandon any well or lease if, in its opinion, such well or lease ceases to produce or is not capable of producing oil, gas or other minerals in commercial quantities. PNR markets the production on terms deemed by it to be the best reasonably obtainable in the circumstances. See "Contracts" on page 13 of this Form 10-K. The Trustee has no power or authority to exercise any control over the operation of the Royalty Properties or the marketing of production therefrom.

The discussions of terms of the Trust Indenture, the Partnership Agreement and the Conveyance contained herein are qualified in their entirety by reference to the Trust Indenture, the Partnership Agreement and the Conveyance themselves, which are exhibits to this Form 10-K and are available upon request from the Trustee.

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

DESCRIPTION OF THE UNITS

Each unit is evidenced by a transferable certificate issued by the Trustee. Each unit ranks equally as to distributions and has one vote on any matter submitted to unitholders. Each unit evidences an undivided interest in the Trust, which in turn owns a 99.99% interest in the Partnership.

Distributions

The Trustee determines for each month the amount of cash available for distribution for such month. Such amount (the "Monthly Distribution Amount") is equal to the excess, if any, of the cash distributed by the Partnership to the Trust during such month, plus any other cash receipts of the Trust during such month (other than interest earned on the Monthly Distribution Amount for any other month), over the liabilities of the Trust paid during such month, and adjusted for changes made by the Trustee during such month in any cash reserves established for the payment of contingent or future obligations of the Trust. The Monthly Distribution Amount for each month is payable to unitholders of record on the monthly record date (the "Monthly Record Date"), which is the close of business on the last business day of such month, or such later date as the Trustee determines is required to comply with legal or stock exchange requirements. However, to reduce the administrative expenses of the Trust, the Trust Indenture provides that the Trustee does not distribute cash monthly, but rather, during January, April, July and October of each year, distributes to each person who was a unitholder of record on a Monthly Record Date during one or more of the immediately preceding three months, the Monthly Distribution Amount for the month or months that he was a unitholder of record, together with interest earned on such Monthly Distribution Amount from the Monthly Record Date to the payment date.

Liability of Unitholders

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

Federal Income Tax Matters

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

This summary is based on current provisions of the Internal Revenue Code of 1986, as amended (the Code), existing and proposed regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may or may not be retroactively applied. Some of the applicable provisions of the Code have not been interpreted by the courts or the Internal Revenue Service (IRS). No assurance can be provided that the statements set forth herein (which do not bind the IRS or the courts) will not be challenged by the IRS or will be sustained by a court if so challenged.

Ownership of Units

The federal income tax consequences to the unitholders of owning units depend on whether the Trust is classifiable as a grantor trust, a non-grantor trust, or a corporation. The Trustee reports on the basis that the Trust is a grantor trust. Based on its recent audit policy, the Internal Revenue Service ("IRS") is expected to concur with such action. No IRS ruling has been received with respect to the Trust, however, and no court case has been decided involving identical facts and circumstances. It is possible, therefore, that the IRS will assert on audit that the Trust is taxable as a corporation and that a court might agree with that assertion.

Income and Depletion

Royalty income, net of depletion and severance taxes, is treated as portfolio income, and, subject to certain exceptions and transitional rules, Royalty income cannot be offset by losses from passive businesses. Additionally, interest income is portfolio income. Administrative expense is an investment expense.

Generally, prior to the Revenue Reconciliation Act of 1990, the transferee of an oil and gas property could not claim percentage depletion with respect to production from the property if it was "proved" at the time of the transfer. This rule is not applicable in the case of transfers of properties after October 11, 1990. Thus, eligible unitholders that acquired units after that date are entitled to claim an allowance for percentage depletion with respect to Royalty income attributable to these units to the extent that this allowance exceeds cost depletion as computed for the relevant period.

Backup Withholding

Distributions from the Trust are generally subject to backup withholding at a rate of 28% of these distributions. Backup withholding will not normally apply to distributions to a unitholder, however, unless a unitholder fails to properly provide to the Trust his taxpayer identification number or the IRS notifies the Trust that the taxpayer identification number provided by a unitholder is incorrect.

Sale of Units

Generally, except for recapture items, the sale, exchange or other disposition of a unit will result in capital gain or loss measured by the difference between the basis in the unit and the amount realized. Effective for property placed in service after December 31, 1986, the amount of gain, if any, realized upon the disposition of oil and gas property is treated as ordinary income up to the amount of intangible drilling and development costs incurred and depletion claimed to the extent it reduced the taxpayer's basis in the property. Under this provision, depletion attributable to a unit acquired after 1986 will be subject to recapture as ordinary income upon disposition of the unit or upon disposition of the oil and gas property to which the depletion is attributable. The balance of any gain or any loss will be capital gain or loss if the unit was held by the unitholder as a capital asset, either long-term or short-term depending on the holding period of the unit. This capital gain or loss will be long-term if a unitholder's holding period exceeded one year as of the date of sale or exchange. A long-term capital gains rate of 15% applies to most capital assets sold with a holding period of more than one year.

Capital gain or loss will be short-term if the unit has not been held for more than one year at the time of disposition.

Non-U.S. Unitholders

In general, a unitholder who is a nonresident alien individual or which is a foreign corporation, each a "non-U.S. unitholder" for purposes of this discussion, will be subject to tax on the gross income produced by the Royalty at a rate equal to 30% (or lower treaty rate, if applicable). This tax will be withheld by the Trustee and remitted directly to the United States Treasury. A non-U.S. unitholder may elect to treat the income from the Royalty as effectively connected with the conduct of a United States trade or business under provisions of the Internal Revenue Code or pursuant to any similar provisions of applicable treaties. Upon making this election a unitholder is entitled to claim all deductions with respect to that income, but he must file a United States federal income tax return to claim these deductions. This election once made is irrevocable unless an applicable treaty allows the election to be made annually.

The Internal Revenue Code and the Treasury Regulations thereunder treat the publicly traded Trust as if it were a United States real property holding corporation. Accordingly, non-U.S. unitholders owning greater than five percent of the outstanding units are subject to United States federal income tax on the gain on the disposition of their units. Non-U.S. unitholders owning five percent or less of the outstanding units are not subject to United States federal income tax on the gain on the disposition of their units.

Federal income taxation of a non-U.S. unitholder is a highly complex matter which may be affected by many other considerations. Therefore, each non-U.S. unitholder should consult with its own tax adviser as to the advisability of its ownership of units.

Tax-Exempt Organizations

The Royalty and interest income should not be unrelated business taxable income so long as, generally, a unitholder did not incur debt to acquire a unit or otherwise incur or maintain a debt that would not have been incurred or maintained if the unit had not been acquired. Legislative proposals have been made from time to time which, if adopted, would result in the treatment of Royalty income as unrelated business income. Tax-exempt unitholders should consult their own tax advisors with respect to the treatment of royalty income.

TERMINATION OF THE TRUST

As discussed above under "Description of the Trust", the terms of the Mesa Offshore Trust Indenture provide that the Trust will terminate upon the first to occur of the following events: (1) the total amount of cash received per year by the Trust for each of three successive years commencing after December 31, 1987 is less than the Termination Threshold or (2) a vote by holders of a majority of the outstanding units in favor of termination. Because the Trust will terminate in the event the total amount of cash received per year by the Trust falls below certain levels, it would be possible for the Trust to terminate even though some of the Royalty Properties continued to have remaining productive lives. For information regarding the estimated remaining life of each of the Royalty Properties and the estimated future net revenues of the Trust based on information provided by PNR, see pages 12 and 13 of this Form 10-K and Note 7 in the Notes to Financial Statements included elsewhere in this Form 10-K. 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. The discussion set forth above is qualified in its entirety by reference to the Trust Indenture itself, which is an exhibit to this Form 10-K and is available upon request from the Trustee.

In addition, in the event of a dissolution of the Partnership (which could occur under the circumstances described above under "Description of the Trust") and a subsequent winding up and termination thereof, the assets of the Partnership (i.e., the Royalty interest) could either (1) be distributed in kind ratably to the Managing General Partner and the Trustee or (2) be sold and the proceeds thereof distributed ratably to the Managing General Partner and the Trustee. In the event of a sale of the Royalty which would include the sale of any interest the Trust may have in estimated plugging and abandonment amounts withheld by PNR, and a distribution of the cash proceeds to the Trustee, the Trustee would make a final distribution to unitholders of such cash proceeds plus any other cash held by the Trust after the payment of or provision for all liabilities of the Trust, and the Trust would be terminated.

Status of the Trust

The Trust Indenture provides that the Trust will terminate if the total amount of cash per year received by the Trust falls below certain levels for each of three successive years (the "Termination Threshold"). As a result of a significant decline in production caused by the Trust properties nearing the end of their estimated productive lives, Royalty income received by the Trust in 2002 and 2003 fell below the Termination Threshold prescribed by the Trust Indenture. In addition, there is an accumulated deficit due PNR as of December 31, 2003 of \$696,712 that will be deducted from any future gross proceeds on the Royalty Properties, which deduction will reduce future Royalty income.

The December 31, 2003 reserve report prepared for the Partnership indicates that Royalty income expected to be received by the Trust in 2004 will be below the Termination Threshold. The Termination Threshold for 2003 was approximately \$1.2 million. The reserve report estimates that future Royalty income to the Trust will be zero for 2004 as estimated net proceeds from the Trust properties during 2004 will not be sufficient to recoup the accumulated deficit existing at December 31, 2003. In addition, the reserve report estimates that future royalty income to the Trust after 2004 will be approximately \$2.2 million (net of the recoupment of the Trust deficit). Future Royalty income in the reserve report was calculated using oil and natural gas spot prices in effect at December 31, 2003 of \$31.42 per barrel and \$5.97 per Mcf, respectively. Based on the current estimates of future Royalty income, the Trustee expects that Royalty income received by the Trust will fall below the Termination Threshold in 2004. **Accordingly, the Trustee anticipates that the Trust will be required to terminate under the provisions of the Trust Indenture effective December 31, 2004.**

PNR advised the Trust that it farmed out the Trust's interest in Brazos A-7 and A-39 so that two exploratory prospects could be drilled during 2003 with the Trust retaining an overriding royalty interest. The first exploration prospect was drilled on Brazos A-7 during 2003 and was determined to be a dry hole. As such, the well was plugged and abandoned. Drilling commenced on the exploration prospect on Brazos A-39 in September 2003 and was still in progress at December 31, 2003. Subsequent to year end, this well reached total depth and PNR is in the process of evaluating development options for the discovery to determine if the project can be sanctioned as commercial. Even if the discovery is deemed to be commercially viable and is developed, it is currently expected that any Royalty income generated from this prospect will not be received in time to eliminate the deficit balance and to increase Royalty income above the Threshold Amount before the Indenture requires the termination of the Trust. In addition, PNR advised the Trust that Stone Energy Corporation is currently drilling an exploratory well on West Delta 61 with the Trust retaining an overriding royalty interest. Results of this exploratory well are expected in the second quarter of 2004. There can be no assurance that this prospect will be successful. Even if this exploratory prospect is successful, it is currently expected that any Royalty income generated from this prospect will not be received in time to eliminate the deficit balance and increase Royalty income above the Threshold Amount before the Trust terminates under the Indenture.

There are numerous uncertainties inherent in estimating and projecting the quantity and value of proved reserves for the Trust properties, as many of the Trust properties are nearing the end of their productive lives and are therefore subject to unforeseen changes in production rates. As such, the foregoing statements reflect only current reasonable expectations.

DESCRIPTION OF ROYALTY PROPERTIES

Producing Acreage and Wells as of December 31, 2003

Property	Producing Acres		Producing Wells(1)			
			Gross		Net	
	Gross	Net(2)	Oil	Gas	Oil	Gas
Offshore Louisiana(3)—						
West Delta 61	5,000	3,750	—	3	—	.3
Offshore Texas(4)—						
Brazos A-7	5,760	2,160	—	1	—	.1
Brazos A-39	5,760	2,160	—	—	—	—
Total	16,520	8,070	—	4	—	.4

- (1) Dual completions are counted as one well. For information regarding wells producing at December 31, 2003, see "Net Proceeds, Production and Average Prices" on page 26 of this Form 10-K. As of March 30, 2003, only the wells on Brazos A-7 and West Delta 61 were producing.
- (2) Net Producing Acres are calculated by multiplying gross producing acres by the net Royalty interest (as defined by the Trust Indenture) attributable to the Trust for each property.
- (3) All wells on South Marsh Island 155 and 156 leases were plugged and abandoned in 2002. PNR abandoned the platform for these two properties in 2003. All wells were plugged and abandoned and the platform was abandoned on West Delta 62 during 2003 and the lease was relinquished.
- (4) All wells were plugged and abandoned and the platform was abandoned on Matagorda Island 624 during 2003 and the lease was relinquished.

Reserves

A study of the proved oil and gas reserves attributable to the Partnership as of December 31, 2003, has been made by PNR. The following letter (the "Reserve Report") summarizes such reserve study. The Reserve Report reflects estimated reserve quantities and future net revenue based upon estimates of the future timing of actual production without regard to when received in cash by the Trust, which differs from the manner in which the Trust recognizes and accounts for its royalty income. For further information regarding the Net Overriding Royalty Interest, the Basis of Accounting for the Trust and Supplemental Reserve Information, see Notes 2, 3 and 6, respectively, in the Notes to Financial Statements contained in Item 8 of this Form 10-K.

March 9, 2004



MESA Offshore Trust
JPMorgan Chase Bank (as Trustee)
700 Lavaca Street, 5th Floor
Austin, Texas 78701-3102

Ladies and Gentlemen:

Pursuant to your request, we have prepared estimates, as of December 31, 2003, of the extent and value of the proved crude oil, condensate, natural gas liquids, and natural gas reserves of certain properties subject to a net profits interest owned by the Mesa Offshore Royalty Partnership, hereinafter referred to as the "Partnership," a partnership owned 99.99 percent by the Mesa Offshore Trust. The interest appraised is referred to herein as the "Partnership Interest" and consists of a 90 percent net profits interest in three Pioneer Natural Resources USA, Inc. (hereinafter referred to as "Pioneer") leases located in the Gulf of Mexico offshore from Louisiana and Texas. The three offshore leases subject to the net profits interest are hereinafter referred to as the "Subject Properties." Reserves of the three leases are reported herein.

The reserve estimates are based on a detailed study of the Subject Properties. The method or combination of methods used in the study of each reservoir was tempered by experience in the area, consideration of the stage of development of the reservoir, and the quality and completeness of basic data.

Estimates of oil, condensate, natural gas liquids and gas reserves and future net revenue should be regarded only as estimates that may change as further production history and additional information become available. Not only are such reserve and revenue estimates based on that information which is currently available, but such estimates are also subject to the uncertainties inherent in the application of judgment factors in interpreting such information.

In the preparation of this report, Pioneer has used internal information with respect to property interests owned by the Partnership, production from such properties, current costs of operation and development, current prices for production, agreements relating to current and future operations and sale of production, and various other information.

The development status shown herein represents the status applicable as of December 31, 2003. Data available from wells drilled on the appraised properties through December 31, 2003 was used in estimating gross ultimate recovery. Gross production estimated to December 31, 2003, was deducted from gross ultimate recovery to arrive at the estimates of gross reserves. In some fields, this required that the production rates be estimated for a portion of 2003 since production data for these properties was not available throughout 2003.

5205 N. O'CONNOR BLVD, SUITE 1400 • IRVING, TEXAS 75039-3740 • MAIN (972) 444-9001 • FAX (972) 969-3587

MESA Offshore Trust
March 9, 2004
Page 2

The reserve volumes and revenue values shown in this report for Partnership Interest were estimated from projections of reserves and revenue attributable to the combined interests consisting of the Partnership Interest and the retained Pioneer Interest in the Subject Properties (Combined Interest). Net reserves attributable to the Partnership Interest were estimated by allocating to the Partnership a portion of the estimated combined net reserves of the Subject Properties based on future revenue. Therefore, the estimated net reserves attributable to the Partnership Interest will vary if different future price and cost assumptions are used.

While estimates of reserves attributable to the Trust are shown in order to comply with requirements of the SEC, there is no precise method of allocating estimates of physical quantities of reserves between the working interest owners and the Trust. The net profits overriding royalty interest is not a working interest and the Trust does not own and is not entitled to receive any specific volume of reserves from the Trust. The quantities of reserves attributable to the Trust will be affected by future changes in various economic factors utilized in estimating future gross and net revenues from the Trust Properties. Therefore, the estimates of reserves set forth in the Reserve Reports are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest.

Petroleum reserves included in this report are classified as proved and are judged to be economically producible in future years from known reservoirs under existing economic and operating conditions and assuming continuation of current regulatory practices using conventional production methods and equipment. In the analysis, reserves were estimated only to the limit of economic rates of production under existing economic and operating conditions using prices and costs as of the date the estimate is made, including consideration of changes in existing prices provided only by contractual arrangements but not including escalations based upon future conditions. The petroleum reserves are classified as follows:

- **Proved**—Reserves that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data. Commercial productivity has been established by actual production, successful testing, or in certain cases by favorable core analyses and electrical-log interpretation when the producing characteristics of the formation are known from nearby fields. Volumetrically, the structure, areal extent, volume, and characteristics of the reservoir are well defined by a reasonable interpretation of adequate subsurface well control and by known continuity of hydrocarbon-saturated material above known fluid contacts, if any, or above the lowest known structural occurrence of hydrocarbons.
- **Developed**—Reserves that are recoverable from existing wells with current operating methods and expenses. Developed reserves include both producing and nonproducing reserves. Estimates of producing reserves assume recovery by existing wells producing from present completion intervals with normal operating methods and expenses. Developed nonproducing reserves are in reservoirs behind the casing or at minor depths below the producing zone and are considered proved by production from other wells in the field, by successful drill-stem tests, or by core analysis from the particular zones. Nonproducing reserves require only moderate expense to be brought into production.
- **Undeveloped**—Reserves that are recoverable from additional wells yet to be drilled. Undeveloped reserves are those considered proved for production by reasonable geological interpretation of adequate subsurface control in reservoirs that are producing or proved by other wells but are not recoverable from existing wells. This classification of reserves requires drilling of additional wells, major deepening of existing wells, or installation of enhanced recovery or other facilities.

MESA Offshore Trust
March 9, 2004
Page 3

Estimates of the net proved reserves attributable to the Partnership Interest, as of December 31, 2003, are as follows:

TOTAL, PROVED RESERVES (PDP+PNP):	
Natural Gas (Mcf)	432,679
Oil and Condensate (bbl)	11,111
Natural Gas Liquids (bbl)	0
PROVED DEVELOPED PRODUCING RESERVES (PDP)	
Natural Gas (Mcf)	432,679
Oil and Condensate (bbl)	11,111
Natural Gas Liquids (bbl)	0

Revenue values attributable to the net proved reserves of the Partnership Interest are expressed in terms of estimated future net revenue and present worth of future net revenue. Future net revenue attributable to the Partnership Interest was estimated monthly from a projection of the combined Pioneer and Partnership future net revenue. Combined future net revenue values were calculated by deducting operating expenses and capital costs from the future gross revenue of the Combined Interest. The monthly values for the aggregate of the Combined Interest in the Subject Properties were reduced by an overhead charge, by a monthly amount necessary for Pioneer to accrue the abandonment costs over the life of the properties, by the deficit balance as described below from the previous month, and by the interest on that deficit balance when such deficits occur. If the adjusted revenue resulting from this calculation was negative, it was carried forward to the next month as a deficit balance. If the adjusted revenue was greater than zero, it was multiplied by a factor of 90 percent to arrive at the future net revenue of the Partnership Interest. The above calculations were made monthly in the aggregate for the Subject Properties. As of December 31, 2003 the Partnership Interest has a deficit balance of \$696,712. Interest is chargeable monthly on the net profits deficit balance at the rate of 9.0 percent per year.

Future oil and gas producing rates estimated for this report are based on production rates considering the most recent figures available or, in certain cases, are based on estimates tempered by Pioneer's experience in the area. The rates used for future production are rates that Pioneer has determined are within the capacity of the well or reservoir to produce.

Gas volumes shown herein are expressed at standard conditions of 60 degrees Fahrenheit and a 15.025 pounds per square inch absolute. Condensate reserves estimated herein are those to be obtained from normal separator recovery.

Revenue values in this report were estimated using current prices and costs. Future prices were estimated using guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board.

The assumptions used for estimating future prices and costs are as follows:

- Oil and Condensate Prices—Oil and condensate prices were held constant for the life of the properties.
- Natural Gas Prices—Gas prices were held constant for the life of the properties.
- Natural Gas Liquids Prices—Natural gas liquids prices were held constant for the life of the properties.
- Operating and Capital Costs—Current estimates of operating costs were used for the life of the properties with no increases in the future based on inflation. Future capital expenditures were estimated using 2003 values and were not adjusted for inflation.

MESA Offshore Trust
March 9, 2004
Page 4

A summary of estimated revenue and costs attributable to the Combined Interest in proved reserves and the future net revenue and present worth attributable to the Partnership Interest, as of December 31, 2003 is as follows:

COMBINED INTEREST:	
Future Gross Revenue (\$)	3,982,549
Production and Ad Valorem Taxes (\$)	0
Operating Costs (\$)	<711,600>
Capital Costs (\$) ¹	<3,111,826>
Future Net Revenue (\$)	159,123
Accrued Revenue for Abandonment Costs (\$)	3,111,826
Future Accrued Revenue for Abandonment Costs (\$)	0
Cumulative Net Profits Deficit @ 12/31/03	774,124
Revenue Subject to Net Profits Interest (\$)	2,496,825
PARTNERSHIP INTEREST:	
Future Net Revenue (\$) ²	2,247,143
Present Worth at 10 Percent (\$)	1,573,433

¹ Is solely made up of future abandonment costs.

² Future income tax expenses were not taken into account in the preparation of these estimates.

The information relating to estimated proved reserves, estimated future net revenue from proved reserves, and present worth of estimated future net revenue from proved reserves of oil, condensate, natural gas liquids, and gas contained in this report has been prepared in accordance with Paragraphs 10-13, 15 and 30(a)-(b) of Statement of Financial Accounting Standards No. 69 (November 1982) of the Financial Accounting Standards Board and Rules 4-10(a)(1)-(13) of Regulation S-X and Rule 302(b) of Regulation S-K of the Securities and Exchange Commission; provided, however, future income tax expenses have not been taken into account in estimating the future net revenue and present worth values set forth herein.

To the extent the above enumerated rules, regulations, and statements require determinations of an accounting or legal nature or information beyond the scope of this report, we are necessarily unable to express an opinion as to whether the above-described information is in accordance therewith or sufficient therefor.

Submitted,



Jay P. Still
Vice President Gulf of Mexico

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures, including many factors beyond the control of the producer. The preceding reserve data in the Reserve Report represent estimates only and should not be construed as being exact. Reserve assessment is a subjective process of estimating the recovery from underground accumulations of gas and oil that cannot be measured in an exact way, and estimates of other persons might differ materially from those of PNR. Accordingly, reserve estimates are often different from the quantities of hydrocarbons that are ultimately recovered.

Also, while estimates of reserves attributable to the Royalty Properties are shown in order to comply with requirements of the "SEC", there is no precise method of allocating estimates of physical quantities of reserves between PNR and the Partnership, since the Royalty is not a working interest and the Partnership does not own and is not entitled to receive any specific volume of reserves from the Royalty. Reserve quantities in the previously mentioned reserve study have been allocated based on the method referenced in the Reserve Report. The quantities of reserves attributable to the Partnership will be affected by future changes in various economic factors utilized in estimating future gross and net revenues from the Royalty Properties. Therefore, the estimates of reserves set forth in the Reserve Report are to a large extent hypothetical and differ in significant respects from estimates of reserves attributable to a working interest.

Moreover, the discounted present values in the Reserve Report should not be construed as the current market value of the estimated gas and oil reserves attributable to the Royalty Properties or the costs that would be incurred to obtain equivalent reserves, since a market value determination would include many additional factors. In accordance with applicable regulations of the SEC, estimated future net revenues were based, generally, on current prices and costs, whereas actual future prices and costs may be materially greater or less. The estimates in the Reserve Report use market prices as of December 31, 2003. These prices (having a weighted average year end price of \$32.47 per barrel and \$5.97 per Mcf as of December 31, 2003) were held constant over the estimated life of the Royalty Properties. These prices were influenced by seasonal demand for natural gas and may not be the most appropriate or representative prices to use for estimating future revenues or related reserve data. The average price of natural gas sold from the Royalty Properties during 2003 was \$6.05 per Mcf, representing a combination of contract prices and spot market prices, while the average price of crude oil, condensate and natural gas liquids was \$27.90 per barrel.

The following is a summary of the estimated remaining life for each of the Royalty Properties provided to the Trustee by PNR as of December 31, 2003. There are numerous uncertainties present in estimating the remaining productive lives for the Royalty Properties. The following summary represents an estimate only and should not be construed as being exact. The estimated remaining productive life of each property varies depending on the recoverable reserves and annual production assumed by PNR. In addition, future economic and operating conditions may cause significant changes in these estimates.

Property	Productive Life(1)(2)
West Delta 61.	7 years
Brazos A-7.	1 year
Brazos A-39	None

-
- (1) The Trust will terminate in the event the total amount of cash received per year by the Trust falls below certain levels. Accordingly, it would be possible for the Trust to terminate even though some of the Royalty Properties continued to have remaining productive lives. See "Termination of the Trust" on page 5 of this Form 10-K.
 - (2) Estimates of remaining lives may vary significantly from year to year.

The future net revenues contained in the Reserve Report have not been reduced for future general and administrative costs and expenses of the Trust, which are expected to approximate \$500,000 annually. The general and administrative costs and expenses of the Trust may increase in future years, depending on the amount of royalty income, increases in accounting, engineering, legal and other professional fees and other factors.

Proceeds, Production and Average Prices

Reference is made to "Net Proceeds, Production and Average Prices" under Item 7 of this Form 10-K.

CONTRACTS

General

PNR has advised the Trust that during 2003 its offshore gas production was marketed under short-term contracts at spot market prices primarily to Occidental Petroleum Corp. and Total S.A. PNR has further advised the Trust that it expects to continue to market its production under short-term contracts for the foreseeable future. Spot market prices for natural gas in 2003 were generally higher than spot market prices in 2002.

Market for Natural Gas

The amount of cash distributions by the Trust is dependent on, among other things, the sales prices for natural gas produced from the Royalty Properties and the quantities of gas sold. The natural gas industry in the United States during the 1990's was affected generally by a surplus in natural gas deliverability in comparison to demand. Demand for gas declined during this period due to a number of factors including the implementation of energy conservation programs, a shift in economic activity away from energy intensive industries and competition from alternative fuel sources such as residual fuel oil, coal and nuclear energy. In late 2001 and early 2002, demand for natural gas increased as a result of the increase in clean burning natural gas fired power generation, the increase in the usage of electrical power fueled by the expanding U.S. economy and a return to seasonally cold winters. Annual wellhead prices generally increased from \$3.69 per Mcf in 2000 to \$4.02 per Mcf in 2001, decreased to \$2.95 per Mcf in 2002, and increased to \$5.09 per Mcf in 2003, according to the Natural Gas Monthly published by the Energy Information Administration of the Department of Energy.

The seasonal nature of demand for natural gas and its effects on sales prices and production volumes may cause the amounts of cash distributions by the Trust to vary substantially on a seasonal basis. Generally, production volumes and prices are higher during the first and fourth quarters of each calendar year due primarily to peak demand in these periods. Because of the time lag between the date on which PNR receives payment for production from the Royalty Properties and the date on which distributions are made to unitholders, the seasonality that generally affects production volumes and prices is generally reflected in distributions to unitholders in later periods.

Competition

The production and sale of gas from the areas in which the Royalty Properties are located is highly competitive and PNR has a number of competitors in these areas. PNR has advised the Trust that it believes that its competitive position in these areas is affected by price, contract terms and quality of service. PNR's business is affected not only by such competition, but also by general economic developments, governmental regulations and other factors.

Marketing of Liquids

PNR generally reserves in its gas purchase contracts the right to extract condensate and other liquid and liquifiable hydrocarbons from all gas produced. PNR is currently selling the condensate and other liquids to various purchasers under contracts with terms of one year or less.

REGULATION AND PRICES

General

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

Operating Hazards and Uninsured Risks

PNR's oil and gas activities are subject to all of the risks normally incident to exploration for and production of oil and gas, including blowouts, cratering and fires, each of which could result in damage to life and property. Offshore operations are subject to a variety of operating risks, such as hurricanes and other adverse weather conditions and lack of access to existing pipelines or other means of transporting production. Furthermore, offshore oil and gas operations are subject to extensive governmental regulations, including certain regulations that may, in certain circumstances, impose absolute liability for pollution damages, and to interruption or termination by governmental authorities based on environmental or other considerations. In accordance with customary industry practices, PNR carries insurance against some, but not all, of these risks. Losses and liabilities resulting from such events would reduce revenues and increase costs to the Trust to the extent not covered by insurance.

FERC Regulation

In recent years, the FERC has required interstate pipeline companies to "unbundle" their services. To the extent a pipeline company or its sales affiliate makes gas sales as a merchant in the future, it does so pursuant to private contracts in direct competition with all other sellers, such as PNR. In recent years, the FERC also has pursued a number of other policy initiatives which could significantly affect the marketing of natural gas. Several of these initiatives are intended to enhance competition in natural gas markets, although some, such as "spindowns" of gathering assets, may have the adverse effect of increasing the cost of doing business on some in the industry. Generally, the FERC retained its existing tests for determining the jurisdictional status of offshore facilities, but eased the application of its jurisdiction over facilities in water depths of 200 meters or more. On February 9, 2001, the FERC issued Order No. 637, which permits, and in some cases requires, interstate natural gas pipelines to make certain changes to the nature of interstate transportation services. In Order No. 637-A, the FERC made certain clarifying adjustments to the regulations promulgated in Order No. 637. In Order No. 637-B, the FERC denied all further requests for rehearing. Order Nos. 637 *et. seq.* currently are pending judicial review. In addition to the changes implemented through Order No. 637, the FERC has stated that it will institute a review of its regulatory model in light of the changes in the natural gas industry. As to all of these recent FERC initiatives, PNR has advised the Trust that the on-going, or, in some instances, preliminary revolving nature of these regulatory initiatives makes it impossible at this time to predict their ultimate impact on the prices, markets or terms of sale of natural gas related to the Trust.

State and Other Regulation

State regulation of gathering facilities generally includes various safety, environmental, and in some circumstances, non-discriminatory take requirements. Some states have implemented more stringent legislation in recent years to regulate gathering rates charged by gas gathering companies, but to date the effect to PNR in connection with the Royalty Properties has been minimal.

Natural gas pipeline facilities used for the transportation of natural gas in interstate commerce are subject to Federal minimum safety requirements. These requirements, however, are not applicable to, *inter alia*,: (1) onshore gathering facilities outside: (i) the limits of any incorporated or unincorporated city, town, or village; and (ii) any designated residential or commercial area; or (2) pipeline facilities on the Outer Continental Shelf ("OCS") upstream of the point at which operating responsibility transfers from a producing operator to a transporting operator. *See* 49 C.F.R. § 192.1(b). We are informed that the Royalty Properties are located in Federal waters on the OCS. The standards governing pipeline safety have undergone recent changes and it is possible that future changes in the regulations and statutes may occur which may increase the stringency of the standards or expand the applicability of the standards to facilities not currently covered.

Environmental

PNR's operations are subject to numerous federal, state and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment, including the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA" or "Superfund"), the Solid Waste Disposal Act, the Clean Air Act, and the Federal Water Pollution Control Act. These laws and regulations, including their state counterparts, can impose liability upon the lessee under a lease for the cost of cleanup of discharged materials resulting from a lessee's operations or can subject the lessee to liability for damages to natural resources. Violations of environmental laws, regulations, or permits can result in civil and criminal penalties as well as potential injunctions curtailing operations in affected areas and restrictions on the injection of liquids into the subsurface that may contaminate groundwater. PNR maintains insurance for costs of cleanup operations, but it is not fully insured against all such risks. A serious release of regulated materials could result in the U.S. Department of the Interior requiring lessees under federal leases to suspend or cease operations in the affected area. In addition, the recent trend toward stricter standards and regulations in environmental legislation is likely to continue. For example, legislation has been proposed in Congress that would reclassify certain oil and gas production wastes as "hazardous wastes" which would subject the handling, disposal and cleanup of these wastes to more stringent requirements and result in increased operating costs for the Royalty Properties, as well as the oil and gas industry in general. State initiatives to further regulate the disposal of oil and gas wastes are also pending in certain states, and these initiatives could have a similar impact on the Royalty Properties.

From time to time, federal and state environmental agencies propose regulations which could have a direct and material impact on PNR's operations. For example, under the Oil Pollution Act of 1990, as amended by the Coast Guard Authorization Act of 1996 (collectively, "OPA"), parties responsible for offshore facilities must establish and maintain evidence of oil-spill financial responsibility ("OSFR") for costs attributable to potential oil spills. OPA requires a minimum of \$35 million in OSFR for offshore facilities located on the OCS. This amount is subject to upward regulatory adjustment up to \$150 million. Responsible parties for more than one offshore facility are required to provide OSFR only for their offshore facility requiring the highest OSFR. In 1998, the Minerals Management Service ("MMS") adopted regulations for establishing the amount of OSFR required for particular facilities. The amount of OSFR increases as the volume of a facility's worst-case oil spill increases. Accordingly, for facilities with worst-case spills of less than 35,000 barrels, only \$35 million in OSFR is required; for worst-case spills of over 35,000 barrels, \$70 million is required; for worst-case spills of over 70,000 barrels, \$105 million is required; and for worst-case spills of over 105,000 barrels, \$150 million is

required. In addition, all OSFR below \$150 million remains subject to upward regulatory adjustment if warranted by the particular operational, environmental, human health or other risks involved with a facility. Under this regulation, PNR is required to maintain \$35 million in OSFR for its offshore facilities. PNR is maintaining its OSFR in this amount by insurance. Although the working interest owners have advised the Trust that current environmental regulation has had no material adverse effect on the working interest owners' present method of operations, the impact of the recently adopted regulatory changes, and of future environmental regulatory developments such as stricter environmental regulation and enforcement policies, cannot presently be quantified. By letter dated November 9, 1995, PNR was advised by the MMS that it does not qualify for a waiver from supplemental bond requirements and that PNR may be required to post supplemental bonds covering its potential obligations with respect to offshore operations. PNR executed a guaranty of abandonment liability (area wide) with the MMS on April 26, 1996, in satisfaction of these obligations.

PNR has advised the Trust that it is not involved in any administrative or judicial proceedings relating to the Royalty Properties arising under federal, state, or local environmental protection laws and regulations which would have a material adverse effect on the Trust's financial position or results of operations.

Platform Abandonment and Removal

PNR is responsible for the abandonment and removal of its offshore drilling and production structures within one year after the cessation of production, although extensions can be requested. PNR withholds from the Trust a reserve to cover its share of those future abandonment and removal costs. See Item 7 and Note 6 in the Notes to Financial Statements for amounts withheld as of December 31, 2003 and amounts to be withheld in the future.

PRINCIPAL TRUST RISK FACTORS

Although risk factors are described elsewhere in this Form 10-K together with specific Cautionary Statements, the following is a summary of the principal risks associated with an investment in units in the Trust.

Natural gas and oil prices fluctuate due to a number of factors, and lower prices will reduce net proceeds available to the Trust and distributions to Trust unitholders.

The Trust's quarterly distributions are highly dependent upon the prices realized from the sale of natural gas and oil. Natural gas and oil 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 disruption, war, or other armed conflict in oil producing regions, in particular the war in Iraq; worldwide economic conditions; weather conditions; the supply and price of foreign natural gas and oil; 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 and oil transportation and price controls, can affect product prices in the long term.

Lower natural gas and oil prices may reduce the amount of natural gas that is economic to produce and reduce net profits available to the Trust. The volatility of energy prices reduces the predictability of future cash distributions to unitholders. Substantially all of the natural gas and natural gas liquids produced from the Royalty Properties is being sold on the spot market or under short-term contracts.

Increased production and development costs for the Royalty will result in decreased Trust distributions.

Production and development costs attributable to the Royalty are deducted in the calculation of the Trust's share of net proceeds. Accordingly, higher or lower production and development costs, without concurrent increases in revenues, directly decrease or increase the amount received by the Trust for the Royalty.

If development and production costs of the Royalty exceed the proceeds of production from the Royalty Properties, the Trust will not receive net proceeds for those properties until future proceeds from production exceed the total of the excess costs plus accrued interest during the deficit period. Development activities may not generate sufficient additional revenue to repay the costs.

Trust reserve estimates depend on many assumptions that may prove to be inaccurate, which could cause both estimates of reserves and estimated future revenues to be too high.

The value of the units of beneficial interest of the Trust depends upon, among other things, the amount of reserves attributable to the Royalty and the estimated future value of the reserves. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation; and
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures.

Changes in these assumptions can materially change reserve estimates.

The reserve quantities attributable to the Royalty and revenues are based on estimates of reserves and revenues for the underlying properties. The method of allocating a portion of those reserves to the Trust is complicated because the Trust holds an interest, indirectly through the Partnership, in the Royalty and does not own a specific percentage of the natural gas reserves.

Estimates and accruals of abandonment costs by PNR may be greater or lesser than future estimated or actual costs.

As discussed in Item 7 and Note 6 to the Notes to Financial Statements, at December 31, 2003 PNR has withheld approximately \$2.8 million for future abandonment costs. To the extent future estimated or actual abandonment costs exceed this amount, PNR would be entitled to withhold such amounts from payments with respect to the Royalty. Similarly, to the extent future estimated or actual abandonment costs are less than this amount, PNR may release such amounts. Only unitholders at the time of any such release and distribution would be entitled to the distribution by the Trust.

Operating risks for the working interest owners' interests in the Royalty Properties can adversely affect Trust distributions.

The occurrence of drilling, production or transportation accidents at any of the Royalty Properties will reduce Trust distributions by the amount of uninsured costs. These occurrences include blowouts, cratering, explosions and other environmental damage. Offshore activities are also subject to a variety of operating risks such as hurricanes and other weather disturbances. These accidents and other natural disasters may result in personal injuries, property damage, damage to productive formations or

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

The operators of the working interest owner are subject to extensive governmental regulation.

Offshore oil and gas operations have been, and in the future will be, affected by federal, state and local laws and regulations and other political developments, such as price or gathering rate controls and environmental protection regulations.

None of the Trustee, the Trust nor its unitholders control the operation or development of the Royalty Properties and have little influence over operation or development.

Neither the Trustee nor the unitholders can influence or control the operation or future development of the underlying properties. The Royalty Properties are owned by PNR as an independent working interest owner. The working interest owner manages the underlying properties and handles receipt and payment of funds relating to the Royalty Properties and payments to the Trust for the Royalty.

PNR, as the current working interest owner, is under no obligation to continue operating the properties. Neither the Trustee nor the unitholders have the right to replace an operator.

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

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

The current working interest owner or any transferee may abandon any well or property if it reasonably believes that the well or property can no longer produce in commercially economic quantities. This could result in termination of the Royalty relating to the abandoned well. Please see "Business—Termination of the Trust" in Item 1 of this Form 10-K.

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

The Trust will be terminated and the Trustee must sell the Royalty if holders of a majority of the units of beneficial interest of the Trust approve the sale or vote to terminate the Trust, or if the total amount of cash received per year by the Trust for each of three consecutive years is less than the Termination Threshold. Following any such termination and liquidation, the net proceeds of any sale will be distributed to the unitholders and unitholders will receive no further distributions from the Trust. We cannot assure you that any such sale will be on terms acceptable to all unitholders. As discussed in Item 1 of this Form 10-K under "Business—Termination of the Trust," the Royalty income received by the Trust was below the Termination Threshold in 2002 and 2003. In addition, based on current estimates of future Royalty income, the Trustee currently expects that Royalty income received by the Trust will fall below the Termination Threshold in 2004. **Accordingly, the Trustee anticipates that the Trust will be required to terminate under the provision of the Trust Indenture effective December 31, 2004.**

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

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

Unitholders have limited voting rights.

Voting rights as a unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of unitholders or for an annual or other periodic re-election of the Trustee. Unlike corporations which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a corporate Trustee in accordance with the Trust Indenture and other organizational documents. The Trustee has extremely limited discretion in its administration of the Trust.

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

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

Item 2. Properties.

Reference is made to Item 1 of this Form 10-K.

Item 3. Legal Proceedings.

There are no pending legal proceedings to which the Trust is a party.

Item 4. Submission of Matters to a Vote of Security Holders.

There were no matters submitted to a vote of unitholders during the fourth quarter of 2003.

PART II

Item 5. Market for the Registrant's Common Equity and Related Unitholder Matters.

The units of beneficial interest of the Trust were delisted from the Pacific Exchange effective May 18, 2001. The Trust units are currently eligible for trading on the OTC Bulletin Board under ticker symbol MOSH. There was no distribution of income for the year ended December 2003, due to a deficit balance owed to PNR. The high and low sales prices and distributions per unit for each quarter in the two years ended December 31, 2003 were as follows:

	2003			2002		
	High	Low	Distribution Paid	High	Low	Distribution Paid
First Quarter	\$ 0.07	\$ 0.01	\$ —	\$ 0.08	\$ 0.05	\$ —
Second Quarter	\$ 0.05	\$ 0.01	\$ —	\$ 0.05	\$ 0.01	\$ —
Third Quarter	\$ 0.05	\$ 0.02	\$ —	\$ 0.03	\$ 0.01	\$ —
Fourth Quarter	\$ 0.03	\$ 0.01	\$ —	\$ 0.03	\$ 0.01	\$ —

At March 24, 2004, the 71,980,216 units outstanding were held by 12,201 unitholders of record.

Item 6. Selected Financial Data.

	2003	2002	2001	1999	1998
Royalty income	\$ —	\$ —	\$ 1,772,595	\$ 3,909,836	\$ 3,474,732
Distributable income	\$ —	\$ —	\$ 1,401,106	\$ 3,586,711	\$ 2,952,611
Distributable income per unit	\$ —	\$ —	\$ 0.0195	\$ 0.0498	\$ 0.0410
Accumulated deficit at year end	\$ (696,712)	\$ (825,616)	\$ (81,329)	\$ —	\$ —
Total assets at year end.	\$ 951,557	\$ 1,497,883	\$ 2,153,070	\$ 3,463,972	\$ 2,455,718

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

The following review of the Trust's financial condition and results of operations should be read in conjunction with the financial statements and notes thereto.

Critical Accounting Policies

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

(a) Royalty income recorded for a month is the Trust's interest in the amount computed and paid by the working interest owner to the Partnership for such month rather than either the value of a portion of the oil and gas sold by the working interest owner for such month or the amount subsequently determined to be 90% 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; and

(c) Trust general and administrative expenses are recorded in the month they accrue and are recoupable from Royalty income.

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, it will differ from the basis used for financial statements prepared in accordance with accounting principles generally accepted in the United States of America because, under such accounting principles, royalty income for a month would be based on net proceeds from sales 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.

Status of the Trust

The Trust Indenture provides that the Trust will terminate if the total amount of cash per year received by the Trust falls below certain levels for each of three successive years (the "Termination Threshold"). As a result of a significant decline in production caused by the Trust properties nearing the end of their estimated productive lives, Royalty income received by the Trust in 2002 and 2003 fell below the Termination Threshold prescribed by the Trust Indenture. In addition, there is an accumulated deficit due PNR as of December 31, 2003 of \$696,712 that will be deducted from any future gross proceeds on the Royalty Properties, which deduction will reduce future Royalty income.

The December 31, 2003 reserve report prepared for the Partnership indicates that Royalty income expected to be received by the Trust in 2004 will be below the Termination Threshold. The Termination Threshold for 2003 was approximately \$1.2 million. The reserve report estimates that future Royalty income to the Trust will be zero for 2004 as estimated net proceeds from the Trust properties during 2004 will not be sufficient to recoup the accumulated deficit at December 31, 2003. In addition, the reserve report estimates that future royalty income to the Trust after 2004 will be approximately \$2.2 million (net of the recoupment of the Trust deficit). Future Royalty income in the reserve report was calculated using oil and natural gas spot prices in effect at December 31, 2003 of \$31.42 per barrel and \$5.97 per Mcf, respectively. Based on the current estimates of future Royalty income, the Trustee expects that Royalty income received by the Trust will fall below the Termination Threshold in 2004. **Accordingly, the Trustee anticipates that the Trust will be required to terminate under the provisions of the Trust Indenture effective December 31, 2004.**

PNR advised the Trust that it farmed out the Trust's interest in Brazos A-7 and A-39 so that two exploratory prospects could be drilled during 2003 with the Trust retaining an overriding royalty interest. The first exploration prospect was drilled on Brazos A-7 during 2003 and was determined to be a dry hole. As such, the well was plugged and abandoned. Drilling commenced on the exploration prospect on Brazos A-39 in September 2003 and was still in progress at December 31, 2003. Subsequent to year end, this well reached total depth and PNR is in the process of evaluating development options for the discovery to determine if the project can be sanctioned as commercial. Even if the discovery is deemed to be commercially viable and is developed, it is currently expected that any Royalty income generated from this prospect will not be received in time to eliminate the deficit balance and to increase Royalty income above the Threshold Amount before the Indenture requires the termination of the Trust. In addition, PNR advised the Trust that Stone Energy Corporation ("Stone") is currently drilling an exploratory well on West Delta 61 with the Trust retaining an overriding royalty interest. Results on this exploratory well are expected in the second quarter of 2004. There can be no assurance that this prospect will be successful. Even if this exploratory prospect is successful, it is currently expected that any Royalty income generated from this prospect will not be received in time to eliminate the deficit balance and increase Royalty income above the Threshold Amount before the Trust terminates under the Indenture.

There are numerous uncertainties inherent in estimating and projecting the quantity and value of proved reserves for the Trust properties, as many of the Trust properties are nearing the end of their productive lives and are therefore subject to unforeseen changes in production rates. As such, the foregoing statements reflect only current reasonable expectations.

Below is additional information regarding the Trust properties provided by PNR:

Properties producing as of December 31, 2003

Property	Number of Producing wells(1)	Estimated Productive Life(1)	Estimated Future Royalty Income(2)
West Delta No. 61	3	7 years	\$ 3,446,390
Brazos A-39	—	None	(219,240)
Brazos A-7	1	1 year	(283,295)

- (1) Information obtained from December 31, 2003 reserve report prepared by PNR.
- (2) Represents estimated future royalty income from the December 31, 2003, reserve report without considering the recoupment by PNR of the accumulated deficit of \$696,712. Future royalty income was calculated using oil and gas spot prices in effect at December 31, 2003 of \$31.42 per barrel and \$5.97 per Mcf. Estimated future net cash outlays on Brazos A-39 and Brazos A-7 represent operating expenses that are required to be incurred until abandonment procedures are commenced.

Properties abandoned or scheduled for abandonment as of December 31, 2003

Property	Status
Brazos A-7	Probable abandonment in 2004 (evaluating for any future exploration opportunities)
Brazos A-39	Probable abandonment in 2004 (pending development determination of discovery and/or any future exploration opportunities)
West Delta 62	Plug and abandonment procedures completed in 2003
South Marsh Island 155	Plug and abandonment procedures completed in 2002
South Marsh Island 156	Plug and abandonment procedures completed in 2002
Vermillion 381	Plug and abandonment procedures completed in 1989
South Pelto 12	Plug and abandonment procedures completed in 1986
Matagorda Island 624	Plug and abandonment procedures completed in 2003
High Island 567	Plug and abandonment procedures completed in 1992

Trust Termination

If the Trust is required to terminate, the Trustee will sell for cash all the assets held in the Trust estate and make a final distribution to the unitholders of any funds remaining after all Trust liabilities have been satisfied.

Financial and Operational Review

As discussed in Item 1 of this Form 10-K, PNR has advised the Trust that during 2003, its offshore gas production was marketed under short-term contracts at spot market prices primarily to Occidental Petroleum Corp. and Total S.A. and that it expects to continue to market its production under short-term contracts for the foreseeable future. Spot market prices for natural gas were on the average higher in 2003 than spot market prices in 2002.

The amount of cash distributed by the Trust is dependent on, among other things, the sales prices and quantities of gas, crude oil, condensate and natural gas liquids produced from the Royalty

Properties and the quantities sold. Substantial uncertainties exist with regard to future gas and oil prices, which are subject to fluctuations due to the regional supply and demand for natural gas and oil, production levels and other activities of the Organization of the Petroleum Exporting Countries ("OPEC") and other oil and gas producers, weather, storage levels, industrial growth, conservation measures, competition and other variables.

Below is a summary of Royalty income received on the Trust properties for each of the three years ending December 31, 2003:

	2003	2002	2001
Gross proceeds @ 90%	\$ 745,192	\$ 848,698	\$ 2,726,068
Operating expenditures @ 90%	(605,927)	(1,232,483)	(953,804)
Capital expenditures @ 90% (1)	(10,348)	(360,576)	(80,829)
Net proceeds (deficit)	128,917	(744,361)	1,691,435
Increase (decrease) in deficit	(128,917)	744,361	81,337
Net proceeds after deficit recovery	—	—	1,772,772
Royalty income (99.99%)	\$ —	\$ —	\$ 1,772,595

- (1) Capital expenditures in 2001 include \$10,000 withheld for future abandonments. As PNR believes that the future abandonments have been fully funded, no such amounts were withheld in 2002 or 2003.

Below is a summary of distributable income for the for years ended December 31, 2003, 2002 and 2001:

	Years Ended December 31,		
	2003	2002	2001
Royalty income	\$ —	\$ —	\$ 1,772,595
Interest income	9,169	22,100	87,538
General and administrative expenses	(9,169)	(22,100)	(459,027)
Distributable income	\$ —	\$ —	\$ 1,401,106
Distributable income per unit	\$ —	\$ —	\$ 0.0195
Accumulated deficit (as of period end)	\$ (696,712)	\$ (825,616)	\$ (81,329)

There was no Royalty income during 2003 and 2002. Since December 2001, the Trust has been in a deficit position to PNR as a result of significant decline in production on properties in which the Trust has a royalty interest. The Trust continues to be in a deficit position as a result of lower production on all properties due to these properties nearing the end of the productive lives. See "—Operational Review" below.

Below is an operational review of the remaining producing Trust properties:

Brazos A-7 and A-39

	2003	2002	2001
Gross proceeds @ 90%	\$ 193,039	\$ 515,950	\$ 1,308,156
Operating expenditures @ 90%	(429,232)	(667,482)	(346,460)
Capital expenditures @ 90% (1)	2,481	(26,483)	(54,809)
Net proceeds (deficit)	\$ (233,712)	\$ (178,015)	\$ 906,887

- (1) Capital expenditures in 2001 include \$6,106 withheld for future abandonments.

The Brazos A-7 and A-39 blocks continued to experience a decrease in natural gas production due to natural production decline. As of December 31, 2003, these two blocks had one well producing, the Brazos A-7 No. B-1 well. The Brazos A-39 No. A-3 well ceased production during the fourth quarter of 2003. PNR farmed out the Trust's interest in both of these blocks so that two exploration prospects could be drilled and in which the Trust will retain an overriding royalty interest. The first prospect on Brazos A-7 was drilled during 2003 and was determined to be a dry hole. As such, the well was plugged and abandoned. Drilling commenced on the exploratory prospect on Brazos A-39 in September 2003 and was still in progress at December 31, 2003. Subsequent to year end, this well reached total depth and PNR is in the process of evaluating development options for the discovery to determine if the project can be sanctioned as commercial. However, there can be no assurance that the project will be sanctioned and it is currently expected that any Royalty income generated from this prospect will not be received in time to eliminate the deficit balance and to increase Royalty income above the Threshold Amount before the Indenture requires the termination of the Trust.

West Delta 61 and 62

	2003	2002	2001
Gross proceeds @ 90%	\$ 552,153	\$ 146,460	\$ 1,019,607
Operating expenditures @ 90%	(176,695)	(394,328)	(279,609)
Capital expenditures @ 90% (1)	(12,829)	—	(3,822)
Net proceeds (deficit)	\$ 362,629	\$ (247,868)	\$ 736,176

(1) Capital expenditures in 2001 include \$3,822 withheld for future abandonments.

The West Delta 61 and 62 blocks experienced an increase in oil and natural gas production during 2003 due to Stone bringing their wells back on production after being shut in to be re-routed to a new platform for production handling. The PNR-operated wells ceased production in 2002, and the wells were plugged and abandoned by year-end with the facilities being completely abandoned during 2003. In 2002, on West Delta 62, the Trust received royalty income from one producing well pursuant to a farm out agreement with Walter Oil and Gas Corporation ("Walter"). Production from this well also ceased in 2002 and Walter completed plugging and abandonment procedures and relinquished the lease. The only remaining wells on this block are in West Delta 61. PNR farmed out a portion of West Delta 61 to Stone retaining a 12.5% (11.25% net to the Trust) overriding royalty interest. Stone has three producing wells on this property and is currently drilling an exploration well with results expected during the second quarter of 2004.

Other Properties

The Matagorda Island 624 block, operated by PNR ceased production in the second quarter of 2002. PNR attempted a workover in the third quarter of 2002, but was unsuccessful. In the first quarter of 2003, PNR plugged and abandoned the wells, and in July 2003, the platform was removed.

The South Marsh Island 155 and 156 blocks ceased production during the first quarter 2000. The abandonment procedures were completed and the lease was relinquished during 2002.

Capital Expenditures

PNR does not anticipate any significant capital expenditures on the Royalty Properties in the future. Due to the limited financial capacity of the Trust, PNR has advised that it intends to farm out the Trust's interest in the blocks it believes may be produced economically, retaining an overriding royalty interest for the Trust.

Abandonment Expenditures

The below table provides a rollforward of the abandonment and removal costs cash reserve that PNR has withheld from the Trust:

Balance, January 1, 2002	\$ 8,324,201
Abandonment cost incurred (SMI 155/156)	(2,683,758)
Balance, December 31, 2002	5,640,443
Abandonment cost incurred (Mat. Is. 624 & WD 62)	(2,839,800)
Balance, December 31, 2003	\$ 2,800,643

Liquidity and Capital Resources

In accordance with the provisions of the Trust conveyance, generally all revenues received by the Trust, net of Trust administrative expenses and any cash reserves established for the payment of contingent or future obligations of the Trust, are distributed currently to the unitholders.

The Trust's source of cash is the Royalty income received from its share of the net proceeds from the Royalty Properties. Reference is made to Note 6 in the Notes to Financial Statements under Item 8 of this Form 10-K for estimates of future Royalty income attributable to the Partnership, of which the Trust has a 99.99% interest.

NET PROCEEDS, PRODUCTION AND AVERAGE PRICES (Unaudited)

	Brazos A-7 and A-39	West Delta 61 and 62	Matagorda Island 624	South Marsh Island 155 and 156	Total
Year Ended December 31, 2003:					
90% of—					
Gross proceeds	\$ 193,039	\$ 552,153	\$ —	\$ —	\$ 745,192
Less 90% of—					
Operating costs	(429,232)	(176,695)	—	—	(605,927)
Capital costs recovered	2,481	(12,829)	—	—	(10,348)
Net Proceeds	<u>\$ (233,712)</u>	<u>\$ 362,629</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 128,917</u>
Trust share of net proceeds (99.99%).					\$ 128,904
Recoupment of deficit					<u>(128,904)</u>
Royalty income					<u>—</u>
Trust Deficit					<u>\$ (696,712)</u>
90% of Production Volumes and Average Sales Prices: Crude oil, condensate and natural gas liquids (Bbls)					
	348	7,266	—	—	7,614
Average sales price per Bbl	<u>\$ 27.42</u>	<u>\$ 27.92</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 27.90</u>
Natural gas (Mcf)	35,644	52,401	—	—	88,045
Average sales price per Mcf	<u>\$ 5.15</u>	<u>\$ 7.26</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 6.05</u>
Producing wells (gross)	1	3	—	—	4
Year Ended December 31, 2002:					
90% of—					
Gross proceeds					
Less 90% of—	\$ 515,950	\$ 146,460	\$ 186,288	\$ —	\$ 848,698
Operating costs	(667,482)	(394,328)	(170,673)	—	(1,232,483)
Capital costs recovered	(26,483)	—	(259,524)	(74,569)	(360,576)
Net Proceeds	<u>\$ (178,015)</u>	<u>\$ (247,868)</u>	<u>\$ (243,909)</u>	<u>\$ (74,569)</u>	<u>\$ (744,361)</u>
Trust share of net proceeds (99.99%)					\$ (744,287)
Increase in deficit					<u>744,287</u>
Royalty income					<u>—</u>
Trust Deficit					<u>\$ (825,616)</u>
90% of Production Volumes and Average Sales Prices: Crude oil, condensate and natural gas liquids (Bbls)					
	434	3,566	850	—	4,850
Average sales price per Bbl	<u>\$ 20.03</u>	<u>\$ 21.46</u>	<u>\$ 20.45</u>	<u>\$ —</u>	<u>\$ 21.15</u>
Natural gas (Mcf)	204,222	24,918	70,687	—	299,827
Average sales price per Mcf	<u>\$ 2.48</u>	<u>\$ 2.81</u>	<u>\$ 2.39</u>	<u>\$ —</u>	<u>\$ 2.49</u>
Producing wells (gross)	2	3	—	—	5
Year Ended December 31, 2001:					
90% of—					
Gross proceeds	\$ 1,308,156	\$ 1,019,607	\$ 403,876	\$ (5,571)	\$ 2,726,068
Less 90% of—					
Operating costs	(346,460)	(279,609)	(187,139)	(140,596)	(953,804)
Capital costs recovered	(48,703)	—	(20,002)	(2,124)	(70,829)
Accrual for future abandonment costs and interest on cost carryforward	(6,106)	(3,822)	(72)	—	(10,000)
Net Proceeds	<u>\$ 906,887</u>	<u>\$ 736,176</u>	<u>\$ 196,663</u>	<u>\$ (148,291)</u>	<u>\$ 1,691,435</u>
Trust share of net proceeds (99.99%)					\$ 1,691,266
Increase in deficit					<u>81,329</u>
Royalty income					<u>1,772,595</u>
Trust deficit					<u>\$ (81,329)</u>
90% of Production Volumes and Average Sales Prices: Crude oil, condensate and natural gas liquids (Bbls)					
	238	15,673	1,369	—	17,280
Average sales price per Bbl	<u>\$ 26.76</u>	<u>\$ 26.25</u>	<u>\$ 25.42</u>	<u>\$ —</u>	<u>\$ 26.19</u>
Natural gas (Mcf)	254,607	112,995	90,227	89	457,918

Average sales price per Mcf	\$	5.11	\$	5.38	\$	4.09	\$	—	\$	4.96
Producing wells (gross)		2		3		1		—		6

- The amounts shown are for the Mesa Offshore Royalty Partnership.
- Producing wells indicates the gross number of wells capable of production as of the end of the period.
- Gross proceeds is based on actual production for a twelve-month period ending on October 31 of each year, respectively.
- Capital costs recovered represent capital costs incurred during the current or prior period to the extent that such costs have been recovered by PNR from gross proceeds.
- The Trust deficit balance of \$696,712 as of December 31, 2003 will be deducted from any future gross proceeds on the Royalty properties, which deduction will reduce future Royalty income.

Production and Price Review

Production volumes for natural gas decreased to 88,045 Mcf in 2003 compared with 299,827 Mcf in 2002 primarily due to natural production decline at Brazos A-7 and A-39 and Matagorda Island 624, partially offset by increased production at West Delta 61 and 62 due to the Stone wells coming back on-line. The average sales price received for natural gas in 2003 was \$6.05 per Mcf compared with \$2.49 per Mcf in 2002. Crude oil, condensate and natural gas liquids production volumes increased to 7,614 barrels in 2003 as compared to 4,850 barrels in 2002. This increase was also the result of the increased production at West Delta 61 and 62 due to the Stone wells coming back on-line, partially offset by the natural production decline at the Brazos A-7 and A-39 and Matagorda Island 624 properties. The average sales price in 2003 for crude oil, condensate and natural gas liquids was \$27.90 per barrel as compared with \$21.15 per barrel in 2002.

Production volumes for natural gas decreased to 299,827 Mcf in 2002 compared with 457,918 Mcf in 2001 primarily due to natural production decline at all properties. The average sales price received for natural gas in 2002 was \$2.49 per Mcf compared with \$4.96 per Mcf in 2001. Crude oil, condensate and natural gas liquids production volumes decreased to 4,850 barrels in 2002 as compared to 17,280 barrels in 2001. This decrease was also the result of the natural production decline at all properties. The average sales price in 2002 for crude oil, condensate and natural gas liquids was \$21.15 per barrel as compared with \$26.19 per barrel in 2001.

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

Not applicable.

Item 8. Financial Statements and Supplementary Data.

**MESA OFFSHORE TRUST
 STATEMENTS OF DISTRIBUTABLE INCOME**

	Years Ended December 31,		
	2003	2002	2001
Royalty income	\$ —	\$ —	\$ 1,772,595
Interest income	9,169	22,100	87,538
General and administrative expenses	(9,169)	(22,100)	(459,027)
Distributable income	\$ —	\$ —	\$ 1,401,106
Distributable income per unit	\$ —	\$ —	\$ 0.0195

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31,	
	2003	2002
ASSETS		
Cash and short-term investments	\$ 938,827	\$ 1,482,810
Interest receivable	1,603	3,946
Net overriding royalty interest in oil and gas properties	380,905,000	380,905,000
Less: accumulated amortization	(380,893,873)	(380,893,873)
Total assets	\$ 951,557	\$ 1,497,883
LIABILITIES AND TRUST CORPUS		
Reserve for trust expenses	\$ 940,430	\$ 1,486,756
Distributions payable	—	—
Trust corpus (71,980,216 units of beneficial interest authorized and outstanding)	11,127	11,127
Total liabilities and trust corpus	\$ 951,557	\$ 1,497,883

STATEMENTS OF CHANGES IN TRUST CORPUS

	Years Ended December 31,		
	2003	2002	2001
Trust corpus, beginning of year	\$ 11,127	\$ 11,127	\$ 23,556
Distributable income	—	—	1,401,106
Distributions to unitholders	—	—	(1,401,106)
Amortization of net overriding royalty interest	—	—	(12,429)
Trust corpus, end of year	\$ 11,127	\$ 11,127	\$ 11,127

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

MESA OFFSHORE TRUST

NOTES TO FINANCIAL STATEMENTS

(1) Trust Organization and Provisions

The Trust

The Mesa Offshore Trust (the "Trust") was created effective December 1, 1982. On that date, Mesa Petroleum Co., predecessor to Mesa Limited Partnership, which was predecessor to MESA Inc., transferred to the Trust a 99.99% interest in the Mesa Offshore Royalty Partnership (the "Partnership"). The Trust is an independent trust administered by JPMorgan Chase Bank, as trustee (the "Trustee"). JPMorgan Chase Bank was formerly known as The Chase Manhattan Bank and is the successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association.

The terms of the Mesa Offshore 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 interest in the Partnership can be sold in part or in total for cash upon approval of the unitholders;
- (c) the Trustee can establish cash reserves and borrow funds to pay liabilities of the Trust and can pledge the assets of the Trust to secure payment of the borrowings;
- (d) the Trustee will make cash distributions to the unitholders in January, April, July and October of each year as discussed more fully in Note 4; and
- (e) the Trust will terminate upon the first to occur of the following events: (i) the total amount of cash received per year by the Trust for each of three successive years commencing after December 31, 1987 is less than ten times one-third of the total amount payable to the Trustee as compensation for such three-year period (the "Termination Threshold") or (ii) a vote by holders of a majority of the outstanding units in favor of termination. Amounts earned by the Trustee as compensation were approximately \$152,000, \$84,000 and \$116,000 for the years 2003, 2002 and 2001, respectively. Upon termination of the Trust, the Trustee will sell for cash all the assets held in the Trust estate and make a final distribution to unitholders of any funds remaining after all Trust liabilities have been satisfied.

The Partnership

The Partnership was created to receive and hold a net overriding royalty interest (the "Royalty") in ten producing and nonproducing oil and gas properties located in federal waters offshore Louisiana and Texas (the "Royalty Properties"). MESA Inc. created the Royalty out of its working interest in the Royalty Properties and transferred it to the Partnership. Until August 7, 1997, MESA Inc. owned and operated its assets through Mesa Operating Co. ("Mesa"), the operator and the managing general partner of the Royalty Properties. 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), a wholly owned subsidiary of Pioneer ("PNR") (collectively, the mergers are referred to herein as the "Merger"). Subsequent to the Merger, Pioneer owns and operates its assets through PNR and is also the managing general partner of the Partnership.

The Partnership is owned 99.99% by the Trust and 0.01% by PNR. PNR serves as the managing general partner of the Partnership. PNR receives no compensation for serving as managing general partner other than the income it receives attributable to its interest in the Partnership.

Status of the Trust

The Trust Indenture provides that the Trust will terminate if the total amount of cash per year received by the Trust falls below certain levels for each of three successive years (the "Termination Threshold"). As a result of a significant decline in production caused by the Trust properties nearing the end of their estimated productive lives, Royalty income received by the Trust in 2002 and 2003 fell below the Termination Threshold prescribed by the Trust Indenture. In addition, there is an accumulated deficit due PNR as of December 31, 2003 of 696,712 that will be deducted from any future gross proceeds on the Royalty Properties, which deduction will reduce future Royalty income.

The December 31, 2003 reserve report prepared for the Partnership indicates that Royalty income expected to be received by the Trust in 2004 will be below the Termination Threshold. The Termination Threshold for 2003 was approximately \$1.2 million. The reserve report estimates that future Royalty income to the Trust will be zero for 2004 as estimated net proceeds from the Trust properties during 2004 will not be sufficient to recoup the accumulated deficit at December 31, 2003. In addition, the reserve report estimates that future royalty income to the Trust after 2004 will be approximately \$2.2 million (net of the recoupment of the Trust deficit). Future Royalty income in the reserve report was calculated using oil and natural gas spot prices in effect at December 31, 2003 of \$31.42 per barrel and \$5.97 per Mcf, respectively. Based on the current estimates of future Royalty income, the Trustee expects that Royalty income received by the Trust will fall below the Termination Threshold in 2004. Accordingly, the Trustee anticipates that the Trust will be required to terminate under the provisions of the Trust Indenture effective December 31, 2004.

PNR advised the Trust that it farmed out the Trust's interest in Brazos A-7 and A-39 so that two exploratory prospects could be drilled during 2003 with the Trust retaining an overriding royalty interest. The first exploration prospect was drilled on Brazos A-7 during 2003 and was determined to be a dry hole. As such, the well was plugged and abandoned. Drilling commenced on the exploration prospect on Brazos A-39 in September 2003 and was still in progress at December 31, 2003. Subsequent to year end, this well reached total depth and PNR is in the process of evaluating development options for the discovery to determine if the project can be sanctioned as commercial. Even if the discovery is deemed to be commercially viable and is developed, it is currently expected that any Royalty income generated from this prospect will not be received in time to eliminate the deficit balance and to increase Royalty income above the Threshold Amount before the Indenture requires the termination of the Trust. In addition, PNR advised the Trust that Stone Energy Corporation is currently drilling an exploratory well on West Delta 61 with the Trust retaining an overriding royalty interest. Results on this exploratory well are expected in the second quarter of 2004. There can be no assurance that this prospect will be successful. Even if this exploratory prospect is successful, it is currently expected that any Royalty income generated from this prospect will not be received in time to eliminate the deficit balance and increase Royalty income above the threshold amount before the Trust terminates under the Indenture.

There are numerous uncertainties inherent in estimating and projecting the quantity and value of proved reserves for the Trust properties, as many of the Trust properties are nearing the end of their productive lives and are therefore subject to unforeseen changes in production rates. As such, the foregoing statements reflect only current reasonable expectations.

(2) Net Overriding Royalty Interest

The instruments conveying the Royalty to the Partnership provide that PNR will calculate and pay to the Partnership each month an amount equal to 90% of aggregate net proceeds for the preceding month. Generally, net proceeds means the excess of the amounts received by PNR from sales of its share of oil and gas from the Royalty Properties (gross proceeds) over the operating and capital costs incurred. Costs exceeding gross proceeds for any month are recovered by PNR, with interest thereon at the prime rate of the Bank of America plus one-half percent, out of future gross proceeds prior to making further royalty payments to the Partnership.

Amortization of the Royalty, which is calculated on the basis of current royalty income in relation to estimated future royalty income, is charged directly to trust corpus since such amounts do not affect distributable income.

(3) Basis of Accounting

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

(a) Royalty income recorded for a month is the Trust's interest in the amount computed and paid by the working interest owner to the Partnership for such month rather than either the value of a portion of the oil and gas produced by the working interest owner for such month or the amount subsequently determined to be 90% 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; and

(c) Trust general and administrative expenses are recorded in the month they accrue and are recoupable from Royalty income.

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, it will differ from the basis used for financial statements prepared in accordance with accounting principles generally accepted in the United States of America because, under such 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.

The instruments conveying the Royalty provide that the working interest owner will calculate and pay the Partnership each month an amount equal to 90% of the net proceeds for the preceding month. Generally, net proceeds means the excess of the amounts received by the working interest owner from sales of oil and gas from the Royalty Properties plus other cash receipts over operating and capital costs incurred. For the twelve months ending December 2003, operating and capital costs incurred exceeded proceeds from oil and gas sales; accordingly, no Royalty income was reported.

There is a deficit balance due PNR as of December 31, 2003 of \$696,712 that will be deducted from any future gross proceeds on the Royalty Properties, which deduction will reduce future Royalty income. In addition, no Royalty income will be distributed to unitholders until the Trustee recoups Trust expenses being paid from the reserve that the Trustee has established for anticipated future expenses. As of December 31, 2003 \$1,059,570 will be recouped by the Trustee from future Royalty

income before Trust distributions will resume. The unexpended amount withheld by PNR for future abandonment costs at December 31, 2003 was \$2,800,643.

(4) Distributions to Unitholders

Under the terms of the Trust Indenture, the Trustee must distribute to the unitholders all cash receipts, after paying liabilities and providing for cash reserves as determined necessary by the Trustee. The amounts distributed are determined on a monthly basis and are payable to unitholders of record as of the last business day of each month. However, cash distributions are made quarterly in January, April, July and October, and include interest earned from the monthly record dates to the dates of distribution.

(5) Federal Income Taxes

The Trustee reports on the basis that the Trust is a grantor trust. Based on its previous audit policy, the Internal Revenue Service (the "IRS") is expected to concur with such action. No IRS ruling has been received or requested with respect to the Trust, however, and no court case has been decided involving identical facts and circumstances. It is possible, therefore, that the IRS would assert upon audit that the Trust is taxable as a corporation and that a court might agree with such assertion.

As a grantor trust, the Trust will incur no federal income tax liability. In addition, it will incur little or no federal income tax liability if it is held to be a non-grantor trust. If the Trust were held to be taxable as a corporation, it would have to pay tax on its net taxable income at the corporate rate.

(6) Supplemental Reserve Information (Unaudited)

Estimates of the proved oil and gas reserves attributable to the Royalty as of December 31, 2003, 2002 and 2001 are based on a report prepared by PNR. The estimates were prepared in accordance with guidelines established by the Securities and Exchange Commission (the "SEC"). Accordingly, the estimates were based on existing economic and operating conditions. The reserve volumes and revenue values contained in the reserve report for the Partnership interest were estimated by allocating to the Partnership a portion of the estimated combined net reserve volumes of the Royalty Properties based on future net revenue. Production volumes are allocated based on royalty income. Because the net reserve volumes attributable to the Partnership interest are estimated using an allocation of reserve volumes based on estimates of future net revenue, a change in prices or costs will result in changes in the estimated net reserve volumes. Therefore, the estimated net reserve volumes attributable to the Partnership interest will vary if different future price and cost assumptions are used. Only costs necessary to develop and produce existing proved reserve volumes were assumed in the allocation of reserve volumes to the Royalty.

Future prices for natural gas were based on prices in effect as of each year end and existing contract terms. Prices being received as of each year end were used for sales of oil, condensate and natural gas liquids. Operating costs, production and ad valorem taxes and future development and abandonment costs were based on current costs as of each year end, with no escalation.

There are numerous uncertainties inherent in estimating the quantities and value of proved reserves and in projecting the future rates of production and timing of expenditures. The reserve data below represent estimates only and should not be construed as being exact. Moreover, the discounted

values should not be construed as representative of the current market value of the Royalty. A market value determination would include many additional factors including: (i) anticipated future oil and gas prices; (ii) the effect of federal income taxes, if any, on the future royalties; (iii) an allowance for return on investment; (iv) the effect of governmental legislation; (v) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities; and (vi) other business risks.

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

The future net revenues contained in the previously mentioned reserve report have not been reduced for future general and administrative expenses of the Trust, which are expected to approximate \$500,000 annually. The general and administrative expenses of the Trust may increase in future years, depending on the amount of royalty income, increases in accounting, engineering, legal, and other professional fees and other factors.

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

Estimated Quantities of Proved and Proved Developed Reserves (Unaudited)

	<u>Oil and Condensate</u>	<u>Natural Gas</u>
	(Bbls)	(Mcf)
Proved Reserves:		
December 31, 2000	36,961	901,408
Revisions of previous estimates	(12,550)	(111,423)
Extensions, discoveries and other additions	—	—
Production	(11,237)	(297,780)
	<u>13,174</u>	<u>492,205</u>
December 31, 2001	13,174	492,205
Revisions of previous estimates	3,487	(59,763)
Extensions, discoveries and other additions	—	—
Production	—	—
	<u>16,661</u>	<u>432,442</u>
December 31, 2002	16,661	432,442
Revisions of previous estimates	(5,550)	237
Extensions, discoveries and other additions	—	—
Production	—	—
	<u>11,111</u>	<u>432,679</u>
December 31, 2003	11,111	432,679
Proved Developed Reserves:		
December 31, 2000.	36,961	901,408
December 31, 2001.	13,174	492,205
December 31, 2002.	16,661	432,442
December 31, 2003.	11,111	432,679

(See Notes on following page.)

**Standardized Measure of Future Royalty Income from
 Proved Oil and Condensate and Gas Reserves, Discounted at 10% Per Annum (Unaudited)**

	December 31,		
	2003	2002	2001
(In thousands)			
Ninety percent of future gross proceeds	\$ 3,584	\$ 3,923	\$ 3,031
Less ninety percent of—			
Future operating costs	(640)	(1,406)	(1,421)
Future capital costs, net of amounts previously accrued	—	—	(23)
Deficit due PNR	(697)	(826)	(81)
Future royalty income	2,247	1,691	1,506
Discount at 10% per annum	(674)	(21)	(256)
Standardized measure of future royalty income from proved oil and gas reserves	<u>\$ 1,573</u>	<u>\$ 1,670</u>	<u>\$ 1,250</u>

**Changes in the Standardized Measure of Future Royalty Income from
 Proved Oil and Gas Reserves, Discounted at 10% Per Annum (Unaudited)**

	Years Ended December 31,		
	2003	2002	2001
(In thousands)			
Standardized measure at beginning of year	\$ 1,670	\$ 1,250	\$ 8,776
Revisions of previous estimates	(675)	(565)	(582)
Net changes in prices and production costs	411	860	(6,049)
Extensions, discoveries and other additions	—	—	—
Royalty income	—	—	(1,773)
Accretion of discount	167	125	878
Net changes in standardized measure	<u>(97)</u>	<u>420</u>	<u>(7,526)</u>
Standardized measure at end of year	<u>\$ 1,573</u>	<u>\$ 1,670</u>	<u>\$ 1,250</u>

- The estimated quantities of proved reserves, standardized measure of future royalty income and changes in the standardized measure represent 100% of amounts for the Partnership in which the Trust has a 99.99% interest.

(7) Selected Quarterly Financial Data (Unaudited)

	Summarized Quarterly Results			
	Three Months Ended			
	March 31	June 30	September 30	December 31
2003:				
Royalty income	\$ —	\$ —	\$ —	\$ —
Distributable income	\$ —	\$ —	\$ —	\$ —
Distributable income per unit	\$ —	\$ —	\$ —	\$ —
2002:				
Royalty income	\$ —	\$ —	\$ —	\$ —
Distributable income	\$ —	\$ —	\$ —	\$ —
Distributable income per unit	\$ —	\$ —	\$ —	\$ —

INDEPENDENT AUDITORS' REPORT

JPMorgan Chase Bank (Trustee) and the Unitholders of the Mesa Offshore Trust:

We have audited the accompanying statements of assets, liabilities and trust corpus of the Mesa Offshore Trust as of December 31, 2003 and 2002, and the related statements of distributable income and changes in trust corpus for the years then ended. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits. The 2001 financial statements of the Mesa Offshore Trust were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those financial statements in their report dated March 25, 2002.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the Trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

These financial statements were prepared on the basis of accounting described in Note 3, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the Mesa Offshore Trust as of December 31, 2003 and 2002, and its distributable income and changes in trust corpus for the years then ended, on the basis of accounting described in Note 3.

The accompanying financial statements have been prepared assuming that the Trust will continue as a going concern. As discussed in Note 1 to the financial statements as a result of a significant decline in production caused by the Trust properties nearing the end of their estimated productive lives, royalty income received by the Trust during 2002 and 2003 fell below the Termination Threshold prescribed by the Trust Indenture. In addition, the Trustee expects that royalty income in 2004 will also fall below the Termination Threshold, resulting in the termination of the Trust effective December 31, 2004. Accordingly, there exists substantial doubt about the Trust's ability to continue as a going concern. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

KPMG LLP

Houston, Texas
March 29, 2004

1. This report is a copy of a previously issued report (See page 33 of the Trust's Annual Report for December 31, 2001 on Form 10-K)
2. The predecessor auditor has not reissued this report.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To JPMorgan Chase Bank (Trustee) and the Unitholders of the Mesa Offshore Trust:

We have audited the accompanying statements of assets, liabilities and trust corpus of the Mesa Offshore Trust as of December 31, 2001 and 2000, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

These financial statements were prepared on the basis of accounting described in Note 3, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the Mesa Offshore Trust as of December 31, 2001 and 2000, and its distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2001, on the basis of accounting described in Note 3.

ARTHUR ANDERSEN LLP

Houston, Texas
March 25, 2002

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

None.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the 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 is accumulated and communicated by Pioneer, as the managing general partner of the Partnership, and the working interest owners to JPMorgan Chase Bank, 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 date of this report, the Trustee carried out an evaluation of the Trustee's disclosure controls and procedures. Mike Ulrich, as Trust Officer of the Trustee, has concluded that the controls and procedures are effective, while noting certain limitations on disclosure controls and procedures as set forth below.

Due to the contractual arrangements of (i) the Trust Indenture, (ii) the Partnership Agreement and (iii) the rights of the Partnership under the Conveyance regarding information furnished by the working interest owners, there are certain potential weaknesses that are not subject to change or modification by the Trustee or its employees. The contractual limitations creating potential weaknesses in disclosure controls and procedures may be deemed to include:

- The working interest owners alone control (i) historical operating data, including production volumes, marketing of products, operating and capital expenditures, environmental and other liabilities, the effects of regulatory changes and the number of producing wells and acreage, (ii) plans for future operating and capital expenditures, (iii) geological data relating to reserves, as well as the reserve report that contains projected production, operating expenses and capital expenses, and (iv) information relating to projected production. While the Trustee requests material information for use in periodic reports as part of its disclosure controls and procedures, the Trustee does not control this information and relies entirely on the working interest owners to provide accurate and timely information when requested for use in the Trust's periodic reports.
- The Trustee relies on information provided by the managing general partner of the Partnership that is collected by the managing general partner from the working interest owners. While the Trustee may request information through the managing general partner, the Conveyance together with the Partnership Agreement gives only the managing general partner of the Partnership, as the Royalty Owner, the actual authority and discretion to request and receive financial information regarding the Royalty Properties from the working interest owners. While the Trustee requests material information for use in periodic reports as part of its disclosure controls and procedures, the Trustee generally does not have any direct contact with working interest owners, other than employees of the managing general partner, and relies on the managing general partner of the Partnership to request and obtain information deemed material to the Trust by the Trustee.
- Under the terms of the Trust Agreement, the Trustee is entitled to rely, and in fact relies, on certain experts in good faith, including the independent auditors with respect to their audit of the Trust and review of financial data provided by the managing general partner and the working interest owners. Other than contracting independent auditors and reviewing information supplied

by the managing general partner, the Trustee makes no independent or direct verification of this financial information. While the Trustee has no reason to believe its reliance upon experts is unreasonable, this reliance on experts and limited access to information may be viewed as a weakness.

The Trustee does not intend to expand its responsibilities beyond those permitted or required by the Trust Indenture and those required under applicable law.

Changes in Internal Controls. To the knowledge of the Trustee, there have been no significant changes in the Trustee's internal controls or in other factors that could significantly affect the Trustee's internal controls subsequent to the date the Trustee completed its evaluation. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal controls of the working interest owners or the managing general partner of the Partnership.

PART III

Item 10. Directors and Executive Officers of the Registrant.

There are no directors or executive officers of the Registrant. The Trustee is a corporate trustee that may be removed by the affirmative vote of a majority of the units then outstanding at a meeting of the holders of units of beneficial interest of the Trust at which a quorum is present.

The Trust does not have a principal executive officer, principal financial officer, principal accounting officer or controller and, therefore, has not adopted a code of ethics applicable to such persons. The Trust does not have a board of directors or an audit committee, and therefore it does not have an audit committee financial expert.

Item 11. Executive Compensation.

Not applicable.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

(a) *Security Ownership of Certain Beneficial Owners.*

<u>Title and Class of Voting Securities</u>	<u>Name and Address of Beneficial Ownership</u>	<u>Amount and Nature of Beneficial Ownership(1)</u>	<u>Percent of Class</u>
Units of Beneficial Interest	MOSH Holding, L.P. Nine Greenway Plaza Suite 3040 Houston, Texas 77046	7,332,887(2)(3)	10.2%

- (1) Under applicable regulations of the Securities and Exchange Commission, securities are deemed to be "beneficially" owned by a person who directly or indirectly holds or shares of voting power with respect thereto.
- (2) Based on information contained in the Form 4 filed on December 23, 2003 and Schedule 13D/A filed on December 16, 2003. These units of beneficial interest of the Issuer (the "Units") are owned directly by Mosh Holding, L.P., a Texas limited partnership ("MOSHLP"). Mosh Holding I, L.L.C., a Texas limited liability company ("MOSHLLC") is the sole general partner of MOSHLP and has sole investment discretion and voting authority with respect to the Units. Charles A. Sharman, Joseph F. Langston, Jr. and Timothy M. Roberson are the sole managers and members of MOSHLLC, in which capacity they may be deemed to share voting control and dispositive power over the Units.

- (3) MOSHLLC and Messrs. Sharman, Langston and Roberson disclaim beneficial ownership of the reported Units except to the extent of their respective pecuniary interest therein.
- (b) *Security Ownership of Management.* Not applicable.
- (c) *Changes in Control.* Registrant knows of no arrangement, including the pledge of securities of the Registrant, the operation of which may at a subsequent date result in a change in control of the Registrant.

Item 13. Certain Relationships and Related Transactions.

Not Applicable.

Item 14. Principle Accountant Fees and Services

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional services firms and related fees are granted by the Trustee.

The following table presents fees for professional audit services rendered by KPMG LLP for the audit of the Mesa Offshore Trust financial statements for 2003 and 2002 and fees billed for other services rendered by KPMG LLP.

	2003	2002
Audit fees ⁽¹⁾	\$ 88,000	\$ 80,100
Audit related fees	—	—
Tax fees ⁽²⁾	25,000	27,000
All other fees	—	—
Total fees	\$ 113,000	\$ 107,100

- (1) Audit fees consist of fees for the audit of the Mesa Offshore Trust financial statements and reimbursement for travel related expenses.
- (2) Tax fees consist of fees related to the Mesa Offshore Trust's tax information for its unitholders paid in 2003 related to 2002 tax work.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K.

(a)(1) Financial Statements

The following financial statements are set forth under Part II, Item 8 of this Annual Report on Form 10-K on the pages indicated.

	<u>Page in this Form 10-K</u>
Statements of Distributable Income	28
Statements of Assets, Liabilities and Trust Corpus	28
Statements of Changes in Trust Corpus.	28
Notes to Financial Statements.	29
Independent Auditors' Report—KPMG LLP	37
Report of Independent Public Accountants—Arthur Andersen LLP	38

(a)(2) Schedules

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

(a)(3) Exhibits

(JPMorgan Chase Bank is successor by mergers to the original name of the Trustee, Texas Commerce Bank National Association)

	<u>SEC File or Registration Number</u>	<u>Exhibit Number</u>
4(a) *Mesa Offshore Trust Indenture between Mesa Petroleum Co. and Texas Commerce Bank National Association, as Trustee, dated December 15, 1982	2-79673	10(gg)
4(b) *Overriding Royalty Conveyance between Mesa Petroleum Co. and Mesa Offshore Royalty Partnership, dated December 15, 1982	2-79673	10(hh)
4(c) *Partnership Agreement between Mesa Offshore Management Co. and Texas Commerce Bank National Association, as Trustee, dated December 15, 1982	2-79673	10(ii)
4(d) *Amendment to Partnership Agreement between Mesa Offshore Management Co., Texas Commerce Bank National Association, as Trustee, and Mesa Operating Limited Partnership, dated December 27, 1985 (Exhibit 4(d) to Form 10-K for year ended December 31, 1992 of Mesa Offshore Trust)	1-8432	4(d)
4(e) *Amendment to Partnership Agreement between Texas Commerce Bank National Association, as Trustee, and Mesa Operating dated as of January 5, 1994 (Exhibit 4(e) to Form 10-K for year ended December 31, 1993 of Mesa Offshore Trust)	1-8432	4(e)
31 Certification furnished pursuant to Section 302 of the Sarbanes-Oxley Act of 2002		
32 Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		

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

(b) Reports on Form 8-K

Current Reports on Form 8-K were filed with the Securities and Exchange Commission on October 21, 2003, November 19, 2003, and December 19, 2003.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MESA OFFSHORE TRUST

By JPMORGAN CHASE BANK, TRUSTEE

By /s/ MIKE ULRICH

Mike Ulrich
Vice President & Trust Officer

March 29, 2004

The Registrant, Mesa Offshore 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.

EXHIBIT INDEX

EXHIBIT NUMBER		SEC File or Registration Number	Exhibit Number
4(a)	*Mesa Offshore Trust Indenture between Mesa Petroleum Co. and Texas Commerce Bank National Association, as Trustee, dated December 15, 1982	2-79673	10(gg)
4(b)	*Overriding Royalty Conveyance between Mesa Petroleum Co. and Mesa Offshore Royalty Partnership, dated December 15, 1982	2-79673	10(hh)
4(c)	*Partnership Agreement between Mesa Offshore Management Co. and Texas Commerce Bank National Association, as Trustee, dated December 15, 1982	2-79673	10(ii)
4(d)	*Amendment to Partnership Agreement between Mesa Offshore Management Co., Texas Commerce Bank National Association, as Trustee, and Mesa Operating Limited Partnership, dated December 27, 1985 (Exhibit 4(d) to Form 10-K for year ended December 31, 1992 of Mesa Offshore Trust)	1-8432	4(d)
4(e)	*Amendment to Partnership Agreement between Texas Commerce Bank National Association, as Trustee, and Mesa Operating dated as of January 5, 1994 (Exhibit 4(e) to Form 10-K for year ended December 31, 1993 of Mesa Offshore Trust)	1-8432	4(e)
31	Certification furnished pursuant to Section 302 of the Sarbanes-Oxley Act of 2002		
32	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002		

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

</TEXT>
</DOCUMENT>

<DOCUMENT>

<TYPE> EX-31

<DESCRIPTION> Exhibit 31

<FILENAME> a2131325zex-31.htm

<TEXT>

EXHIBIT 31

CERTIFICATION

I, Mike Ulrich, certify that:

1. I have reviewed this annual report on Form 10-K of Mesa Offshore Trust, for which JPMorgan Chase Bank acts as Trustee;
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, distributable income and changes in trust corpus of the registrant as of, and for, the periods presented in this annual report;
4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)), for for the registrant and have:
 - a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under my supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this annual report is being prepared;
 - b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report my conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and
 - c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the registrant's internal control over financial reporting; and
5. I have disclosed, based on my most recent evaluation, to the registrant's auditors:
 - a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting, which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) any fraud, whether or not material, that involves any persons who have a significant role in the registrant's internal controls; and

In giving the foregoing certifications in paragraphs 4 and 5, I have relied to the extent I consider reasonable on information provided to me by the working interest owners and the managing general partner of the Mesa Offshore Trust Partnership, in which the registrant owns a 99.99% interest.

Date: March 29, 2004

By: /s/ MIKE ULRICH

Mike Ulrich,
Vice President and Trust Officer
JPMorgan Chase Bank

</TEXT>
</DOCUMENT>

<DOCUMENT>

<TYPE> EX-32

<DESCRIPTION> Exhibit 32

<FILENAME> a2131325zex-32.htm

<TEXT>

EXHIBIT 32

March 29, 2004

Via EDGAR
Securities and Exchange Commission
Judiciary Plaza
450 Fifth Street, N.W.
Washington, D.C. 20549

Re: Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of
the Sarbanes-Oxley Act of 2002

Ladies and Gentlemen:

In connection with the Annual Report of Mesa Offshore Trust (the "Trust") on Form 10-K for the year ended December 31, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, not in its individual capacity but solely as the trustee of the Trust, certifies pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to its knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Trust at the dates and for the periods presented.

The above certification is furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350) and is not being filed as part of the Form 10-K or as a separate disclosure document.

JPMORGAN CHASE BANK,
Trustee for Mesa Offshore Trust

By: /s/ MIKE ULRICH

Mike Ulrich
Vice President and Trust Officer

</TEXT>
</DOCUMENT>

<DOCUMENT>

<TYPE> GRAPHIC

<DESCRIPTION> G1003879.jpg

<FILENAME> g1003879.jpg

<TEXT>

GRAPHIC File
</TEXT>
</DOCUMENT>

<DOCUMENT>

<TYPE> GRAPHIC

<DESCRIPTION> G768395.jpg

<FILENAME> g768395.jpg

<TEXT>

GRAPHIC File
</TEXT>
</DOCUMENT>

</SUBMISSION>