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

FORM 10-K

(Mark One)

[X] Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended October 31, 2013 or

[ ] 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 1-8245

NORTH EUROPEAN OIL ROYALTY TRUST
(Exact name of registrant as specified in its charter)

Delaware	22-2084119
(State of organization)	(IRS Employer Identification Number)

Suite 19A, 43 West Front Street, Red Bank, N.J.	07701
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number including area code: 732-741-4008

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

Title of each class	Name of each exchange on which registered
Units of Beneficial Interest	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ____ No _X_

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ____ No _X_

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 _X_ No___

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes___ 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. __X__

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ____	Accelerated filer _X_
Non-accelerated filer ____	Smaller reporting company ____

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

As of April 30, 2013, the aggregate market value of outstanding units of beneficial interest of the registrant held by non-affiliates of the registrant was $226,205,823 on such date.

As of December 30, 2013, there were 9,190,590 units of beneficial interest ("units") of the registrant outstanding.

Documents Incorporated by Reference

Items 10, 11, 12, 13 and 14 of Part III have been partially or wholly omitted from this report and the information required to be contained therein is incorporated by reference from the registrant's definitive proxy statement for the annual meeting to be held on February 11, 2014.

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Table of Contents

PART I

Item 1. Business.

(a) General Development of Business. Registrant (the "Trust") is a grantor trust which, on behalf of the owners of beneficial interest in the Trust (the "unit owners"), holds overriding royalty rights covering gas and oil production in certain concessions or leases in the Federal Republic of Germany. The rights are held under contracts with local German exploration and development subsidiaries of ExxonMobil Corp. ("ExxonMobil") and the Royal Dutch/Shell Group of Companies ("Royal Dutch/Shell Group"). Under these contracts, the Trust receives various percentage royalties on the proceeds of the sales of certain products from the areas involved. At the present time, royalties are received for sales of gas well gas, oil well gas, crude oil, distillate and sulfur. See Item 2 of this Report for descriptions of the relationships of these companies and certain of these contracts.

The royalty rights were received by the Trust from North European Oil Company (the "Company") upon dissolution of the Company in September 1975. The Company was organized in 1957 as the successor to North European Oil Corporation (the "Corporation"). The Trust is administered by trustees (the "Trustees") under an Agreement of Trust dated September 10, 1975, as amended (the "Trust Agreement").

Neither the Trust nor the Trustees on behalf of the Trust conduct any active business activities or operations. The function of the Trustees is to monitor, verify, collect, hold, invest and distribute the royalty payments made to the Trust. Under the Trust Agreement, the Trustees make quarterly distributions of the net funds received by the Trust on behalf of the unit owners. Funds temporarily held by the Trust are invested in interest bearing bank deposits, money market accounts, certificates of deposit, U.S. Treasury Bills or other government obligations.

There has been no significant change in the principal operation or purpose of the Trust during the past fiscal year.

As part of the Sarbanes-Oxley Act of 2002 ("SOX"), the Securities and Exchange Commission (the "SEC") has adopted rules implementing legislation concerning governance matters for publicly held entities. The Trust is complying with the requirements of the SEC and SOX and, at this time, the Trustees have chosen not to request any relief from those provisions based on the passive nature of the Trust. In that connection, the Trustees have directed that certain of the additional statements and disclosures set forth or incorporated by reference in this Report, which the SEC requires of corporations, be made even though some of such statements and disclosures might not now or in the future be required to be made by the Trust.

In addition, the New York Stock Exchange (the "NYSE"), where units of beneficial interest of the Trust are listed for trading, has adopted additional corporate governance rules as set forth in Section 303A of the NYSE Listed Company Manual. Most of the governance requirements promulgated by the NYSE are not applicable to the Trust, which is a passive entity acting as a royalty trust and holds only overriding royalty rights. The Trust does not engage in any operating or active business. The Trustees have, however, chosen to constitute an Audit Committee and a Compensation Committee but may not necessarily do so in the future.

(b) Financial Information about Segments. Since the Trust conducts no active business operations, an analysis by segments is accordingly not applicable to the Trust. To the extent that royalty income received by the Trust is attributable to sales of different products, to sales from different geographic areas or to sales by different operating companies, this information is set forth in Item 2 of this Report and the Exhibit described in that Item 2.

(c) Narrative Description of Business. Under the Trust Agreement, the Trust conducts no active business operations and is restricted to collection of income from royalty rights and distribution to unit owners of the net income after payment of administrative and related expenses.

The overriding royalty rights held by the Trust are derived from contracts and agreements originally entered into by German subsidiaries of the predecessor Corporation during the early 1930s. The Trust's primary royalty rights are based on government granted concessions and remain in effect as long as there are continued production activities and/or exploration efforts by the operating companies. It is generally anticipated that the operating companies will continue production where it remains economically profitable for them to do so. In addition, the Trust holds other royalty rights, which are based on leases which have passed their original expiration dates. These leases remain in effect as long as there is continued production or the lessor does not cancel the lease. Individual lessors will normally not seek termination of the rights originally granted because the leases provide for royalty payments to the lessors if sales of oil or gas result from discoveries made on the leased land. Additionally, termination by individual lessors would result in the escheat of mineral rights to the applicable state.

Royalties are paid to the Trust on sales from production under these leases and concessions by the operating companies on a regular monthly or quarterly basis pursuant to the royalty agreements. The operating companies make royalty payments to the Trust exclusively in Euros. As promptly as possible after the funds are deposited in the Trust's bank account in Germany, they are converted into U.S. dollars at the exchange rate in effect on that date and transferred to the Trust's bank account in the U.S. The Trust does not engage in activities to hedge against currency risk and the fluctuations in the conversion rate impact its financial results. However, since the actual royalty deposits are held as Euros for such a limited time, the market risk is small. The Trust has not experienced any difficulty in effecting the conversion of Euros into U.S. dollars.

As the holder of overriding royalty rights, the Trust has no legal ability, whether by contract or operation of law, to compel production. Moreover, if an operator should determine to terminate production in any concession or lease area and to surrender the concession or lease, the royalty rights for that area would thereby be terminated. Under certain royalty agreements, the operating companies are required to advise the Trust of any intention to surrender lease or concession rights. While the Trust itself is precluded from undertaking any production activities, possible residual rights might permit the Trust to take up a surrendered concession or lease and attempt to retain a third party operator to develop such concession or lease.

The exploration for and the production of gas and oil is a speculative business. The Trust has no means of ensuring continued income from its royalty rights at either their present levels or otherwise. The Trust has no role in any of the operating companies' decision making processes, such as gas pricing, gas sales or exploration, which can impact royalty income. In addition, fluctuations in prices and supplies of gas and oil and the effect these fluctuations might have on royalty income to the Trust and on reserves net to the Trust cannot be accurately projected. Finally, natural gas and crude oil are wasting assets. While known reserves may increase as additional development adds quantities to the reserve amount, the amount of known and unknown reserves is finite and will decline over time. Given these factors, along with the uncertainty in worldwide and local German economic conditions and the fact that the Trustees have no information beyond that information which is generally available to the public, the Trustees make no projections regarding future royalty income.

While Germany has laws relating to environmental protection, the Trustees have no detailed information concerning the present or possible effect of such laws on operations in areas where the Trust holds royalty rights on production and sale of products from those areas.

Seasonal demand factors affect the income from royalty rights insofar as they relate to energy demands and increases or decreases in prices, but on average they are generally not material to the regular annual income received under the royalty rights.

The Trust, either itself or in cooperation with holders of parallel royalty rights, arranges for periodic examinations of the books and records of the operating companies to verify compliance with the computation provisions of the applicable agreements. From time to time, these examinations disclose computational errors or errors from inappropriate application of existing agreements and appropriate adjustments are requested and made. These periodic examinations may also disclose matters that are subject to dispute between the parties.

(d) Financial Information about Geographic Areas. The Trust does not engage in any active business operations, and its sources of income are the overriding royalty rights covering gas, sulfur and oil production in certain areas in Germany and interest on the funds temporarily invested by the Trustees. In Item 2 of this Report, there is a schedule (by product, geographic area and operating company) showing the royalty income received by the Trust during the fiscal year ended October 31, 2013.

(e) Trustees and Executive Officers of the Trust. As specified in the Trust Agreement, the affairs of the Trust are managed by not more than five individual Trustees who receive compensation determined under that same agreement. One of the Trustees is designated as Managing Trustee and receives additional compensation in such capacity. Robert P. Adelman has served as Managing Trustee (non-executive) since November 1, 2006. In addition, Samuel

M. Eisenstat serves as Chairman for the Audit and Compensation Committees. Lawrence A. Kobrin serves as Clerk to the Trustees, a role similar to that of a corporate secretary. For these services these two individuals receive additional compensation.

Day-to-day matters are handled by the Managing Director, John R. Van Kirk, who also serves as CEO and CFO. John R. Van Kirk has held the position of Managing Director of the Trust since November 1990. The Managing Director provides office space and services at cost to the Trust.

In addition to the Managing Director, the Trust has one administrative employee in the United States, whose title is Administrator. The Trust has retained the services of a consultant in Germany who has broad experience in the petroleum industry and from whom it receives reports on a regular basis. Because the Trust has only two employees, employee relations or labor contracts are not directly material to the business or income of the Trust. The Trustees have no information concerning employee relations of the operating companies.

(f) Available Information. The Trust maintains a website at www.neort.com. The Trust's annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and related amendments are available free of charge through the Trust's website as soon as reasonably practicable after such reports are filed with or furnished to the SEC. The North European Oil Royalty Trust Agreement (as amended), the Trust's Code of Conduct and Business Ethics, the Trustees' Regulations and the Trust's Audit Committee Charter are also available on the Trust's website. The Trust's website and the information contained in it and connected to it shall not be deemed incorporated by reference into this Form 10-K.

Item 1A. Risk Factors.

The results of operations and financial condition of the Trust are subject to various risks. Some of these risks are described below, and you should take such risks into account in evaluating the Trust or any investment decision involving the Trust. This section does not describe all risks that may be applicable to the Trust and it is intended only as a summary of certain material risk factors. More detailed information concerning the risk factors described below is contained in other sections of this Annual Report on Form 10-K.

The Trust does not conduct any active business activities or operations and has no legal ability to compel production.

The Trust holds overriding royalty rights only. It is a passive entity and conducts no operations. It can exert no influence on the operating companies that conduct exploration, drilling, production and sales activities in the areas covered by the Trust's overriding royalty rights. Thus, the Trust has no means of ensuring continued income from its overriding royalty rights. The failure of an operator to conduct its operations, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations, including environmental laws and regulations, in a proper manner could have an adverse effect on the net proceeds payable to the Trust. The Trust also has no right to remove or replace an operator.

The current operating companies are under no obligation to continue operations in the royalty areas. Natural gas is a wasting asset. The production and sale of natural gas, from which the Trust derives its royalties, reduces the amount of remaining proved producing reserves of natural gas. If the operating companies do not perform additional development projects which replace at least a portion of the current production, the anticipated life of the Trust will not be extended and could be shortened. Absent further additions to the amount of proved producing reserves, production and sales will reach a point in the future where the level of sales will no longer be commercially viable and production will cease. Ultimately, the amount of known and unknown reserves within a defined area, such as the Oldenburg concession, is finite and will decline over time.

Trust reserve estimates depend on many assumptions that may prove to be inaccurate, and these inaccuracies may cause errors in the reserve estimates.

The value of Trust units may depend in part on the reserves attributable to the royalty areas. The calculations performed in the process of estimating proved producing reserves are inherently uncertain. The accuracy of any reserve estimate is a function of the quality of available data, engineering interpretation and judgment, and the assumptions used regarding the quantities of recoverable natural gas and the future prices of crude oil and natural gas. The Trust currently receives quarterly reports from the operating companies with respect to production and sales on either a well-by-well or an area-wide basis. The Trust also receives annual reports from the operating companies with respect to current and planned drilling and exploration efforts.

These reports are very limited in nature. The unified exploration and production venture, ExxonMobil Production Deutschland GmbH ("EMPG"), which provides these reports to the Trust, continues to limit the information flow to that which is required by German law, and the Trust has no legal or contractual right to compel the issuance of additional information. The Trust's inability to compel the delivery of detailed information with respect to individual wells increases the possibility of inaccuracy in the petroleum engineering consultant's estimates of reserves.

Actual production, revenues and expenditures by the operating companies for the royalty areas, and therefore actual net proceeds payable to the Trust, will vary from estimates and those variations could be material.

The effects of fluctuations in prices of gas and oil and changes in worldwide and local economic conditions on the royalty income paid to the Trust cannot be accurately projected.

The Trust's distributions are highly dependent upon the prices realized from the sale of natural gas and a decrease in such prices could reduce the amount of cash distributions paid to unit owners.

Oil and natural gas prices and demand for these products can fluctuate widely in response to a variety of factors that are beyond the control of the Trust. Factors that contribute to these fluctuations include, among others: (1) worldwide and German economic conditions and levels of economic activity; (2) political and economic conditions in major oil producing regions, especially in the Middle East and Russia; (3) weather conditions; (4) the price of oil or natural gas imported into Germany; (5) the level of consumer demand in Germany; (6) the increasing role of alternate energy sources along with the German government's and European Union's role in promoting those sources; and (7) German and European Union governmental actions intended to broaden sources of energy supply.

When oil and natural gas prices decline, the Trust is affected in two ways. First, net income from the royalty areas is reduced. Second, exploration and development activity by the operating companies on the royalty areas may decline as some projects may become uneconomic and are either delayed or eliminated. It is impossible to predict future oil and natural gas price movements, and this, along with other factors, make future cash distributions to unit owners impossible to predict.

There are continuing and growing efforts underway to decouple the linkage between oil prices and gas prices, that has historically existed in European gas supply contracts. In recent years as oil prices have increased, that linkage has supported higher gas prices. A spot market has developed in Europe in recent years with corresponding spot market prices for gas where the gas price is not linked to oil prices. For decades, the European gas market has valued stability of supply over price considerations. In recent years with the advent of additional sources of supply and concerns over high energy prices, there has been a shift in this position to one where price has been given a larger role. Whether the efforts to completely remove the linkage will succeed cannot be determined. However, there are increasing indications that efforts to decouple the price of gas from the price of oil are strengthening and that the occasions of spot market prices being utilized in gas sale contracts may be growing. At this time we cannot predict what impact such decoupling might have on the Trust and its royalty income.

Changes in the dollar value of the Euro have both an immediate and long-term impact on the Trust.

For unit owners, changes in the dollar value of the Euro have both an immediate and long-term impact. The immediate impact is from the exchange rate that is applied at the time the royalties, paid to the Trust in Euros, are converted into U.S. dollars at the time of their transfer from Germany to the United States. In relation to the dollar, a stronger Euro would yield more dollars and a weaker Euro would yield less dollars.

The long-term impact relates to the mechanism of gas pricing contained in some of the gas sales contracts negotiated by the operating companies. These gas sales contracts often use the price of German light heating oil as one of the primary pricing factors by which the contractual price of gas is determined. The price of German light heating oil, which is a refined product, is largely determined by the price of the imported crude oil from which it was refined. Oil on the international market is priced in dollars. However, when oil is imported into Germany it is purchased in Euros, and at this point the dollar value of the Euro becomes relevant. A weaker Euro would buy less oil making that oil and the subsequently refined light heating oil more expensive. A stronger Euro would buy more oil making that oil and the subsequently refined light heating oil less expensive. Since changes in the price of German light heating oil are subsequently reflected in the price of gas through the gas sales contracts, the dollar/Euro relationship can make the prices of gas higher or lower. The changes in gas prices that result from changes in the prices of German light heating oil are only reflected after a built-in delay of three to six months as specified in the individual gas sales contracts. For gas that is sold on the spot market or between Mobil Erdgas and BEB using spot market prices (intra-company sales), there is no long-term impact because there is no relationship between the price of gas and the price of oil for these sales.

Item 1B. Unresolved Staff Comments.

None

Item 2. Properties.

The properties of the Trust, which the Trust and Trustees hold pursuant to the Trust Agreement on behalf of the unit owners, are overriding royalty rights on sales of gas, sulfur and oil under certain concessions or leases in the Federal Republic of Germany. The actual leases or concessions are held either by Mobil Erdgas-Erdol GmbH ("Mobil Erdgas"), a German operating subsidiary of ExxonMobil, or by Oldenburgische Erdolgesellschaft ("OEG"). As a result of direct and indirect ownership, ExxonMobil owns two-thirds of OEG and the Royal Dutch/Shell Group owns one-third of OEG. The Oldenburg concession (1,398,000 acres), covering virtually the entire former Grand Duchy of Oldenburg and located in the German federal state of Lower Saxony, provides nearly 100% of the royalties received by the Trust. BEB Erdgas und Erdol GmbH ("BEB"), a joint venture in which ExxonMobil and the Royal Dutch/Shell Group each own 50%, administers the concession held by OEG. In 2002, Mobil Erdgas and BEB formed EMPG to carry out all exploration, drilling and production activities. All sales activities are still handled by either Mobil Erdgas or BEB.

Under one set of rights covering the western part of the Oldenburg concession (approximately 662,000 acres), the Trust receives a royalty payment of 4% on gross receipts from sales by Mobil Erdgas of gas well gas, oil well gas, crude oil and condensate (the "Mobil Agreement"). Under the Mobil Agreement there is no deduction of costs prior to the calculation of royalties from gas well gas and oil well gas, which together account for approximately 98% of all the royalties under said agreement. Historically, the Trust has received significantly greater royalty payments under the Mobil Agreement (as compared to the OEG Agreement described below) due to the higher royalty rate specified by that agreement.

The Trust is also entitled under the Mobil Agreement to receive a 2% royalty on gross receipts of sales of sulfur obtained as a by-product of sour gas produced from the western part of Oldenburg. The payment of the sulfur royalty is conditioned upon sales of sulfur by Mobil Erdgas at a selling price above an agreed upon base price. This base price is adjusted annually by an inflation index. When the average selling price falls below the indexed base price, no royalties are payable. Prior to the second quarter of fiscal 2008, the Trust had not received any royalties from sulfur sales under the Mobil Agreement for over 10 years and for fiscal 2009 and 2010 sulfur royalties were only received intermittently. During fiscal 2011, the Trust received four sulfur royalty payments attributable to each of the four quarters. During fiscal 2012 and fiscal 2013, the Trust received four payments representing quarterly sulfur royalties. Sulfur royalties under the Mobil Agreement totaled $600,514, $825,369 and $613,203 during fiscal 2013, 2012 and 2011, respectively.

Under another set of rights covering the entire Oldenburg concession and pursuant to the agreement with OEG, the Trust receives royalties at the rate of 0.6667% on gross receipts from sales by BEB of gas well gas, oil well gas, crude oil, condensate and sulfur (removed during the processing of sour gas) less a certain allowed deduction of costs (the "OEG Agreement"). Under the OEG Agreement, 50% of the field handling, treatment and transportation costs as reported for state royalty purposes are deducted from the gross sales receipts prior to the calculation of the royalty to be paid to the Trust.

In addition to the Oldenburg area, the Trust also holds overriding royalties at various rates on a number of leases of various sizes in other areas of northwest Germany. At the present time, all but one of these leases are in the non-producing category. Due to the low level of income and the intermittent gas production from the single producing lease, Grosses Meer, reserves from this lease are not included in reserve calculations for this report year. In 2008, the German authorities requested that the operating companies conduct a reservoir analysis of the Grosses Meer leasehold area to determine whether the royalties were being properly allocated based on the locations of the gas reserves. As a consequence, the payment of royalties to the Trust was suspended. Following the completion of the reservoir analysis, a cumulative royalty payment of $61,548 was received by the Trust in the third quarter of fiscal 2010. This payment covered the years 2005 through 2009 and the first quarter of calendar 2010. Since fiscal 2010, production and royalties from Grosses Meer continued to be intermittent and minimal. Royalties from Grosses Meer were $0, $3,813 and $0 during fiscal 2013, 2012 and 2011, respectively.

The following is a schedule of royalty income for the fiscal year ended October 31, 2013 by product, geographic area and operating company:

By Product:

Product	Royalty Income
Gas Well and Oil Well Gas	$ 19,962,499
Sulfur	$ 1,158,528
Oil	$ 425,271

By Geographic Area:

Area	Royalty Income
Western Oldenburg	$ 16,701,384
Eastern Oldenburg	$ 4,844,914
Non-Oldenburg Areas	$ 0

By Operating Company:

Company	Royalty Income
Mobil Erdgas (under the Mobil Agreement)	$ 14,339,348
BEB (under the OEG Agreement)	$ 7,206,950

Exhibit 99.1 to this Report is a report entitled Calculation of Cost Depletion Percentage for the 2013 Calendar Year Based on the Estimate of Remaining Proved Producing Reserves in the Northwest Basin of the Federal Republic of Germany as of October 1, 2013 (the "Cost Depletion Report"). The Cost Depletion Report, dated December 13, 2013, was prepared by Ralph E. Davis Associates, Inc., 1717 St. James Place, Suite 460, Houston, Texas 77056 ("Davis Associates"). Davis Associates is an independent petroleum and natural gas consulting organization specialized in analyzing hydrocarbon reserves.

The Cost Depletion Report provides documentation supporting the calculation of the cost depletion percentage for the 2013 calendar year based on the use of certain production data and the estimated net proved producing reserves as of October 1, 2013 for the primary area in which the Trust holds overriding royalty rights. The cost depletion percentage is prepared for the Trust's unit owners for tax reporting purposes. In order to permit timely filing of the Cost Depletion Report and consistent with the practice of the Trust in prior years, the information has been prepared for the 12-month period ended September 30, 2013. While this is one month prior to the end of the fiscal year of the Trust, the information available for production and sales through the end of September is the most complete information available at a date early enough to permit the timely preparation of the various reports required. Unit owners are referred to the full text of the Cost Depletion Report contained herein for further details.

The primary purpose of the Cost Depletion Report is the preparation of the cost depletion percentage for use by unit owners in their own tax reporting. The only information provided to the Trust that can be utilized in the calculation of the cost depletion percentage is current and historical production and sales of proved producing reserves. For the western half of the Oldenburg Concession, the Trust received quarterly production and sales information on a well-by-well basis. For the eastern half of the Oldenburg Concession, the Trust receives cumulative quarterly production and sales information on two general areas. These general areas encompass numerous fields with varying numbers of wells. Pursuant to the arrangements under which the Trust holds royalty rights and the fact that the Trust is not considered an operating company within Germany, the Trust has no access to the operating companies' proprietary information concerning producing field reservoir data. The Trustees have been advised by its German counsel that publication of such information is not required under applicable law in Germany and that the royalty rights do not grant the Trust the right to require or compel the release of such information. Past efforts to obtain such information from the operating companies have not been successful. The information made available to the Trust by the operating companies does not include any of the following: reserve estimates, capitalized costs, production cost estimates, revenue projections, producing field reservoir data (including pressure data, permeability, porosity and thickness of producing zone) or other similar information. While the limited information available to the Trust permits the calculation of the cost depletion percentage, it does not change the uncertainty with respect to the estimate of proved producing reserves. In addition, it is impossible for the Trust or its consultant to make estimates of proved undeveloped or probable future net recoverable oil and gas by appropriate geographic areas.

The Trust has the authority to examine, but only for certain limited purposes, the operating companies' sales and production from the royalty areas. The Trust also has access to published materials in Germany from W.E.G. (a German organization equivalent to the American Petroleum Institute or the American Gas Association). The use of such statistical information relating to production and sales necessarily involves extrapolations and projections. Both Davis Associates and the Trustees believe the use of the material available is appropriate and suitable for preparation of the cost depletion percentage and the estimates described in the Cost Depletion Report. Both the Trustees and Davis Associates believe this report and these estimates to be reasonable and appropriate but assume that these estimates may vary from statistical estimates which could be made if reservoir production information (of the kind normally available to producing companies in the United States) were available. The limited information available makes it inappropriate to make projections or estimates of proved or probable reserves of any category or class other than the estimated net proved producing reserves described in the Cost Depletion Report.

Attachment A of the Cost Depletion Report shows a schedule of estimated net proved producing reserves of the Trust's royalty properties, computed as of October 1, 2013 and a five year schedule of gas, sulfur and oil sales for the twelve months ended September 30, 2013, 2012, 2011, 2010 and 2009 computed from quarterly sales reports of operating companies received by the Trust during such periods.

Item 3. Legal Proceedings.

The Trust is not a party to any pending legal proceedings. The previous litigation commenced by the Trust in Germany against the operating companies (See 2011 Annual Report on Form 10-K) was concluded after an adverse district court ruling in May 2012, from which the Trust and its co-plaintiff, after consultation with their local counsel, determined not to appeal.

Item 4. Mine Safety Disclosure.

Not Applicable.

PART II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

The Trust's units of beneficial interest are listed for trading on the New York Stock Exchange under the symbol NRT. Under the Trust Agreement, the Trustees distribute to unit owners, on a quarterly basis, the net royalty income after deducting expenses and reserving limited funds for anticipated administrative expenses. As of November 30, 2013, there were 850 unit owners of record.

The following table presents the high and low closing prices for the quarterly periods ended in fiscal 2013 and 2012 as reported by the NYSE as well as the cash distributions paid to unit owners by quarter for the past two fiscal years.

Fiscal Year 2013

Quarter Ended	Low Closing Price	High Closing Price	Distribution per Unit
January 31, 2013	$21.80	$28.25	$0.59
April 30, 2013	$23.35	$27.00	$0.64
July 31, 2013	$24.00	$26.18	$0.49
October 31, 2013	$21.54	$26.06	$0.53

Fiscal Year 2012

Quarter Ended	Low Closing Price	High Closing Price	Distribution per Unit
January 31, 2012	$30.31	$33.66	$0.66
April 30, 2012	$31.97	$33.19	$0.68
July 31, 2012	$27.25	$33.66	$0.61
October 31, 2012	$27.96	$31.65	$0.51

The quarterly distributions to unit owners represent their undivided interest in royalty payments from sales of gas, sulfur and oil during the previous quarter. Each unit owner is entitled to recover a portion of his or her investment in these royalty rights through a cost depletion percentage. The calculation of this cost depletion percentage is set forth in detail in Attachment B to the Cost Depletion Report attached as Exhibit 99.1 to this Form 10-K.

The Cost Depletion Report has been prepared by Davis Associates using the limited information described in Item 2 of this Report to which reference is made. The Trustees believe that the calculations and assumptions used in the Cost Depletion Report are reasonable according to the facts and circumstances of available information. The cost depletion percentage recommended by the Trust's independent petroleum and natural gas consultants for calendar 2013 is 10.6104%. Specific details relative to the Trust's income and expenses and cost depletion percentage as they apply to the calculation of taxable income for the 2013 calendar year are included on special removable pages in the 2013 Annual Report. Additionally, the tax reporting information for 2013 is available on the Trust's website, www.neort.com, in the section marked Tax Letters contained within the Tax Information section.

The Trust does not maintain any compensation plans under which units are authorized for issuance. The Trust did not make any repurchases of Trust units during fiscal 2013, 2012 or 2011 and has never made such repurchases.

Item 6. Selected Financial Data.

NORTH EUROPEAN OIL ROYALTY TRUST

SELECTED FINANCIAL DATA (CASH BASIS)

FOR FIVE FISCAL YEARS ENDED OCTOBER 31, 2013

	2013	2012	2011	2010	2009
German gas, sulfur and oil royalties received	$21,546,298	$23,672,808	$25,148,523	$19,645,331	$28,724,078
Net income	$20,635,306	$22,609,961	$24,195,907	$18,720,265	$27,699,228
Net income per unit (a)	$ 2.25	$ 2.46	$ 2.63	$ 2.04	$ 3.01
Units of beneficial interest outstanding at end of year (a)	9,190,590	9,190,590	9,190,590	9,190,590	9,190,590
Distributions per unit paid or to be paid to unit owners	$ 2.25	$ 2.46	$ 2.63	$ 2.04	$ 3.01
Total assets at year end	$ 4,918,491	$ 4,778,200	$ 5,971,867	$ 5,211,966	$ 3,586,198

(a) Net income per unit was calculated based on the number of units outstanding at the end of the fiscal year.

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

Executive Summary

The Trust is a passive fixed investment trust which holds overriding royalty rights, receives income under those rights from certain operating companies, pays its expenses and distributes the remaining net funds to its unit owners. As mandated by the Trust Agreement, distributions of income are made on a quarterly basis. These distributions, as determined by the Trustees, constitute substantially all of the funds on hand after provision is made for Trust expenses then anticipated.

The Trust does not engage in any business or extractive operations of any kind in the areas over which it holds royalty rights and is precluded from engaging in such activities by the Trust Agreement. There are no requirements, therefore, for capital resources with which to make capital expenditures or investments in order to continue the receipt of royalty revenues by the Trust.

The properties of the Trust are described in Item 2. Properties of this report. Of particular importance with respect to royalty income are the two royalty agreements, the Mobil Agreement and the OEG Agreement. The Mobil Agreement covers gas sales from the western part of the Oldenburg concession. Under the Mobil Agreement, the Trust has traditionally received the majority of its royalty income due to the higher royalty rate of 4%. The OEG Agreement covers gas sales from the entire Oldenburg concession but the royalty rate of 0.6667% is significantly lower and gas royalties have been correspondingly lower.

The operating companies pay monthly royalties to the Trust based on their sales of natural gas, sulfur and oil. Of these three products, natural gas provides approximately 93% of the total royalties. The amount of royalties paid to the Trust is primarily based on four factors: the amount of gas sold, the price of that gas, the area from which the gas is sold and the exchange rate.

At approximately the 25th of the months of January, April, July and October, the operating companies calculate the amount of gas sold during the previous calendar quarter and determine the amount of royalties that were payable to the Trust based on those sales. This amount is divided into thirds and forms the monthly royalty payments (payable on the 15th of each month) to the Trust for its upcoming fiscal quarter. At the same time that the operating companies determine the actual amount of royalties that were payable for the prior calendar quarter, they look at the actual amount of royalties that were paid to the Trust for that period and calculate the difference between what was paid and what was payable. Additional amounts payable by the operating companies are paid immediately and any overpayment is deducted from the payment for the first month of the following fiscal quarter. In September of each year, the operating companies make the final determination of any necessary royalty adjustments for the prior calendar year with a positive or negative adjustment made accordingly. The Trust's German accountants review the royalty calculations on a biennial basis.

There are two types of natural gas found within the Oldenburg concession, sweet gas and sour gas. Sweet gas has little or no contaminants and needs no treatment before it can be sold. In recent years, sweet gas has assumed the role of swing producer. During periods of high demand, the production of sweet gas is increased as necessary. During the summer months, sweet gas production is reduced due to a general decline in demand. Sour gas, in comparison, must be processed at either the Grossenkneten or the Norddeutsche Erdgas-Aufbereitungs GmbH ("NEAG") desulfurization plants before it can be sold. The desulfurization process removes hydrogen sulfide and other contaminants. The hydrogen sulfide in gaseous form is converted to sulfur in a solid form and sold separately. For efficiency purposes, Grossenkneten is operated at capacity on a continual basis. As needed, the operators conduct maintenance on the plants, generally during the summer months when demand is lower.

Under the Mobil and OEG Agreements, the gas is sold either to various distributors under long-term contracts (which delineate, among other provisions, the timing, manner, volume and price of the gas sold) or the gas is sold at the spot market prices. Gas sold at spot market prices is either sold directly on the spot market or the gas is sold between Mobil Erdgas and BEB (intra-company sales). With regard to gas sales under the long-term contracts, the pricing mechanisms contained in these contracts include a delay factor of three to six months and often specify the use the price of light heating oil in Germany as one of the primary pricing components. Since Germany must rely on imports to meet the majority of its energy demands, oil prices on the international market (in U.S. dollars) have a significant impact on the price of light heating oil in Germany and a delayed impact on the price of gas. The price of gas sold on the spot market or sold between Mobil Erdgas and BEB is not based on a relationship to the price of oil but instead at the quoted market price of gas then trading as determined by supply and demand. The Trust itself does not have access to the specific sales contracts under which gas from the Oldenburg concession is sold. However, working under a confidentiality agreement with the operating companies, the Trust's German accountants review both the contractual sales and spot market or intra-company sales periodically on behalf of the Trust to verify their correctness. The Trust's accountants in Germany are in the process of conducting their examination of the operating companies for 2011 and 2012 and, when their report is complete, they may be able to provide further insight into the issue of spot market prices and their impact on the Trust.

For unit owners, changes in the dollar value of the Euro have both an immediate and long-term impact. The immediate impact is from the exchange rate that is applied at the time the royalties, paid to the Trust in Euros, are converted into U.S. dollars at the time of their transfer from Germany to the United States. In relation to the dollar, a stronger Euro would yield more dollars and a weaker Euro would yield less dollars. The long-term impact relates to the mechanism of gas pricing contained in some of the gas sales contracts negotiated by the operating companies. These gas sales contracts often use the price of German light heating oil as one of the primary pricing factors by which the price of gas is determined. The price of German light heating oil, which is a refined product, is largely determined by the price of the imported crude oil from which it was refined. Oil on the international market is priced in dollars. However, when oil is imported into Germany it is purchased in Euros, and at this point the dollar value of the Euro becomes relevant. A weaker Euro would buy less oil making that oil and the subsequently refined light heating oil more expensive. A stronger Euro would buy more oil making that oil and the subsequently refined light heating oil less expensive. Since changes in the price of German light heating oil are subsequently reflected in the price of gas through the gas sales contracts, the dollar/Euro relationship can make the prices of gas higher or lower. The changes in gas prices that result from changes in the prices of German light heating oil are only reflected after a built-in delay of three to six months as specified in the individual gas sales contracts. With regard to either spot market or intra-company sales, there is no long-term impact because there is no relationship between the price of gas and the price of oil.

Seasonal demand factors affect the income from the Trust's royalty rights insofar as they relate to energy demands and increases or decreases in prices, but on average they are generally not material to the annual income received under the Trust's royalty rights.

The Trust has no means of ensuring continued income from overriding royalty rights at their present level or otherwise. The Trust's consultant in Germany provides general information to the Trust on the German and European economies and energy markets. This information provides a context in which to evaluate the actions of the operating companies. In his position as the Trust's consultant, he receives reports from EMPG with respect to current and planned drilling and exploration efforts. However, EMPG and the operating companies continue to limit the information flow to that which is required by German law.

The low level of administrative expenses of the Trust limits the effect of inflation on costs. Sustained price inflation would be reflected in sales prices. Sales prices along with sales volumes form the basis on which the royalties paid to the Trust are computed. The impact of inflation or deflation on energy prices in Germany is delayed by the use, in certain long-term gas sales contracts, of a delay factor of three to six months prior to the application of any changes in light heating oil prices to gas prices.

Results: Fiscal 2013 versus Fiscal 2012

For fiscal 2013, the Trust's gross royalty income decreased 8.98% to $21,546,298 from $23,672,808 in fiscal 2012. The decrease in royalty income is due to declines in gas sales. The impact of this factor was reduced but not completely offset by the increase in gas prices and average exchange rates. The decrease in the amount of royalty income resulted in the lower distributions. The total distribution for fiscal 2013 was $2.25 per unit compared to $2.46 per unit for fiscal 2012. As in prior years, the Trust receives adjustments from the operating companies based on their final calculations of royalties payable during the previous calendar year. In the fourth fiscal quarter of 2013, the prior year adjustment represented a minor positive impact of $0.0043 per unit. In the fourth quarter of fiscal 2012, the prior year adjustment represented a negative impact of approximately $0.0189 per unit.

Under the Mobil Agreement, gas sales declined 9.88% to 33.829 Billion cubic feet ("Bcf") in fiscal 2013 from 37.539 Bcf in fiscal 2012. Since the Trust does not receive information about the decision making process of the operating companies, it is impossible to determine to what extent, if any, which factors may have impacted gas sales. According to the Trust's consultant in Germany, it is most likely that the decline in gas production is due to the normal reduction in well pressure that is experienced over time which has not been fully offset by the addition of new wells and production capacity.

Quarterly and Yearly Gas Sales under the Mobil Agreement in Billion cubic feet

Fiscal Quarter	2013 Gas Sales	2012 Gas Sales	Percentage Change
First	8.897	9.749	- 8.74%
Second	8.656	9.632	- 10.13%
Third	8.102	9.140	- 11.36%
Fourth	8.174	9.018	- 9.36%
Fiscal Year Total	33.829	37.539	- 9.88%

Average prices for gas sold under the Mobil Agreement increased 0.19% to 2.7066 €cents/kWh in fiscal 2013 from 2.7015 €cents/kWh in fiscal 2012.

Average Gas Prices under the Mobil Agreement in Euro cents per Kilowatt Hour

Fiscal Quarter	2013 Gas Prices	2012 Gas Prices	Percentage Change
First	2.9620	2.8563	+ 3.70%
Second	2.4352	2.8708	- 15.17%
Third	2.7651	2.6666	+ 3.69%
Fourth	2.6583	2.3884	+11.30%
Fiscal Year Avg.	2.7066	2.7015	+ 0.19%

Converting gas prices into more familiar terms, using the average exchange rate, yielded a price of $10.24 per thousand cubic feet ("Mcf"), a 2.71% increase over fiscal 2012's average price of $9.97/Mcf. For fiscal 2013, royalties paid under the Mobil Agreement were converted and transferred at an average Euro/dollar exchange rate of $1.3172, an increase of 2.47% from the average Euro/dollar exchange rate of $1.2854 for fiscal 2012.

Average Euro Exchange Rate under the Mobil Agreement

Fiscal Quarter	2013 Average Euro Exchange Rate	2012 Average Euro Exchange Rate	Percentage Change
First	1.3158	1.3017	+ 1.08%
Second	1.3105	1.3024	+ 0.62%
Third	1.3090	1.2530	+ 4.47%
Fourth	1.3334	1.2824	+ 3.98%
Fiscal Year Avg.	1.3172	1.2854	+ 2.47%

Excluding the effects of differences in prices and average exchange rates, the combination of royalty rates on gas sold from western Oldenburg results in an effective royalty rate approximately seven times higher than the royalty rate on gas sold from eastern Oldenburg. This is of particular significance to the Trust since gas sold from western Oldenburg provides the bulk of royalties paid to the Trust. For fiscal 2013, the volume of gas sold from western Oldenburg accounted for only 32.76% of the volume of all gas sales. However, western Oldenburg gas royalties provided approximately 77.93% or $15,556,093 out of a total of $19,962,499 in overall Oldenburg gas royalties.

Under the OEG Agreement, gas sales decreased 3.01% to 103.256 Bcf in fiscal 2013 from 106.457 Bcf in fiscal 2012. Since the Trust does not receive information about the decision making process of the operating companies, it is impossible to determine to what extent, if any, which factors may have impacted gas sales. According to the Trust's consultant in Germany, it is most likely that the decline in gas production is due to the normal reduction in well pressure that is experienced over time which has not been fully offset by the addition of new wells and production capacity.

Quarterly and Yearly Gas Sales under the OEG Agreement in Billion cubic feet

Fiscal Quarter	2013 Gas Sales	2012 Gas Sales	Percentage Change
First	27.117	28.187	- 3.80%
Second	26.508	26.104	+ 1.55%
Third	24.436	26.254	- 6.92%
Fourth	25.195	25.912	- 2.77%
Fiscal Year Total	103.256	106.457	- 3.01%

Average gas prices for gas sold under the OEG Agreement increased 2.37% to 2.8561 €cents/kWh in fiscal 2013 from 2.7900 €cents/kWh in fiscal 2012.

Average Gas Prices under the OEG Agreement in Euro cents per Kilowatt Hour

Fiscal Quarter	2013 Gas Prices	2012 Gas Prices	Percentage Change
First	3.0363	2.9205	+ 3.97%
Second	2.9002	3.0872	- 6.06%
Third	2.7696	2.5079	+ 10.44%
Fourth	2.7003	2.6346	+ 2.49%
Fiscal Year Avg.	2.8561	2.7900	+ 2.37%

Converting gas prices into more familiar terms, using the average exchange rate, yielded a price of $10.51/Mcf, a 4.68% increase over fiscal 2012's average price of $10.04/Mcf. For fiscal 2013, royalties paid under the OEG Agreement were converted and transferred at an average Euro/dollar exchange rate of $1.3136, an increase of 2.19% from the average Euro/dollar exchange rate of $1.2854 for fiscal 2012.

Average Euro Exchange Rate under the OEG Agreement

Fiscal Quarter	2013 Average Euro Exchange Rate	2012 Average Euro Exchange Rate	Percentage Change
First	1.3083	1.3028	+ 0.42%
Second	1.3105	1.3019	+ 0.66%
Third	1.3048	1.2488	+ 4.48%
Fourth	1.3352	1.2845	+ 3.95%
Fiscal Year Avg.	1.3136	1.2854	+ 2.19%

Interest income for fiscal 2013 decreased 36.84% to $25,363 as compared to $40,156 for fiscal 2012 reflecting the reduction in royalty receipts. Trust expenses decreased 15.11% to $936,355 in fiscal 2013 from $1,103,003 in fiscal 2012 primarily due to the absence of legal costs associated with the litigation in Germany, the absence of accounting costs associated with the biennial royalty examination for the years 2009 and 2010 and the reduction in Trustees fees as specified according to the provisions of the Trust Agreement.

<u>Results: Fiscal 2012 versus Fiscal 2011</u>

For fiscal 2012, the Trust's gross royalty income decreased 5.87% to $23,672,808 from $25,148,523 in fiscal 2011. The decrease in royalty income is due to declines in gas sales and average exchange rates. The impact of these factors was reduced but not completely offset by the increase in gas prices. The decrease in the amount of royalty income resulted in the lower distributions. The total distribution for fiscal 2012 was $2.46 per unit compared to $2.63 per unit for fiscal 2011. As in prior years, the Trust receives adjustments from the operating companies based on their final calculations of royalties payable during the previous calendar year. In the fourth quarter of fiscal 2012, the prior year adjustment represented a negative impact of approximately $0.0189 per unit. In the fourth fiscal quarter of 2011, the Trust received only a nominal prior year adjustment.

Under the Mobil Agreement, gas sales declined 13.62% to 37.539 Bcf in fiscal 2012 from 43.456 Bcf in fiscal 2011. Since the Trust does not receive information about the decision making process of the operating companies, it is impossible to determine to what extent, if any, which factors may have impacted gas sales. According to the Trust's consultant in Germany, it is possible that the decline in gas production is due to the normal reduction in well pressure that is experienced over time which has not been fully offset by the addition of new wells and production capacity.

Quarterly and Yearly Gas Sales under the Mobil Agreement in Billion cubic feet

Fiscal Quarter	2012 Gas Sales	2011 Gas Sales	Percentage Change
First	9.749	11.707	-16.73%
Second	9.632	11.057	-12.89%
Third	9.140	10.671	-14.35%
Fourth	9.018	10.021	-10.01%
Fiscal Year Total	37.539	43.456	-13.62%

Average prices for gas sold under the Mobil Agreement increased 10.61% to 2.7015 €cents/kWh in fiscal 2012 from 2.4424 €cents/kWh in fiscal 2011.

Average Gas Prices under the Mobil Agreement in Euro cents per Kilowatt Hour

Fiscal Quarter	2012 Gas Prices	2011 Gas Prices	Percentage Change
First	2.8563	2.3753	+20.25%
Second	2.8708	2.5087	+14.43%
Third	2.6666	2.3838	+11.86%
Fourth	2.3884	2.5102	- 4.85%
Fiscal Year Avg.	2.7015	2.4424	+10.61%

Converting gas prices into more familiar terms, using the average exchange rate, yielded a price of $9.97/Mcf, a 2.68% increase over fiscal 2011’s average price of $9.71/Mcf. For fiscal 2012, royalties paid under the Mobil Agreement were transferred at an average Euro/dollar exchange rate of $1.2854, a decrease of 7.34% from the average Euro/dollar exchange rate of $1.3872 for fiscal 2011.

Average Euro Exchange Rate under the Mobil Agreement

Fiscal Quarter	2012 Average Euro Exchange Rate	2011 Average Euro Exchange Rate	Percentage Change
First	1.3017	1.3431	- 3.08%
Second	1.3024	1.3962	- 6.72%
Third	1.2530	1.4091	-11.08%
Fourth	1.2824	1.3938	- 7.99%
Fiscal Year Avg.	1.2854	1.3872	- 7.34%

Excluding the effects of differences in prices and average exchange rates, the combination of royalty rates on gas sold from western Oldenburg results in an effective royalty rate approximately seven times higher than the royalty rate on gas sold from eastern Oldenburg. This is of particular significance to the Trust since gas sold from western Oldenburg provides the bulk of royalties paid to the Trust. For fiscal 2012, gas sales from western Oldenburg accounted for only 35.26% of all gas sales. However, western Oldenburg gas royalties provided approximately 81.56% or $17,702,882 out of a total of $21,705,858 in overall Oldenburg gas royalties.

Under the OEG Agreement, gas sales decreased 10.22% to 106.457 Bcf in fiscal 2012 from 118.577 Bcf in fiscal 2011. Since the Trust does not receive information about the decision making process of the operating companies, it is impossible to determine to what extent, if any, which factors may have impacted gas sales. According to the Trust's consultant in Germany, it is possible that the decline in gas production is due to the normal reduction in well pressure that is experienced over time which has not been fully offset by the addition of new wells and production capacity.

Quarterly and Yearly Gas Sales under the OEG Agreement in Billion cubic feet

Fiscal Quarter	2012 Gas Sales	2011 Gas Sales	Percentage Change
First	28.187	30.213	- 6.71%
Second	26.104	30.098	-13.27%
Third	26.254	29.595	-11.29%
Fourth	25.912	28.671	- 9.62%
Fiscal Year Total	106.457	118.577	-10.22%

Average gas prices for gas sold under the OEG Agreement increased 5.74% to 2.7900 €cents/kWh in fiscal 2012 from 2.6386 €cents/kWh in fiscal 2011.

Average Gas Prices under the OEG Agreement in Euro cents per Kilowatt Hour

Fiscal Quarter	2012 Gas Prices	2011 Gas Prices	Percentage Change
First	2.9205	2.5404	+14.96%
Second	3.0872	2.6826	+15.08%
Third	2.5079	2.5379	- 1.18%
Fourth	2.6346	2.7998	- 5.90%
Fiscal Year Avg.	2.7900	2.6386	+ 5.74%

Converting gas prices into more familiar terms, using the average exchange rate, yielded a price of $10.04/Mcf, a 1.95% decrease over fiscal 2011's average price of $10.24/Mcf. For fiscal 2012, royalties paid under the OEG Agreement were transferred at an average Euro/dollar exchange rate of $1.2854, a decrease of 7.49% from the average Euro/dollar exchange rate of $1.3894 for fiscal 2011.

Average Euro Exchange Rate under the OEG Agreement

Fiscal Quarter	2012 Average Euro Exchange Rate	2011 Average Euro Exchange Rate	Percentage Change
First	1.3028	1.3436	- 3.04%
Second	1.3019	1.3989	- 6.93%
Third	1.2488	1.4148	- 11.73%
Fourth	1.2845	1.3929	- 7.78%
Fiscal Year Avg.	1.2854	1.3894	- 7.49%

Reflecting a shift in May 2011 to royalty receipts being deposited in a Money Market account versus being used to purchase T-Bills, interest income for fiscal 2012 increased 53.07% to $40,156 as compared to $26,233 for fiscal 2011. Trust expenses increased 12.68% to $1,103,003 in fiscal 2012 from $978,849 in fiscal 2011 primarily due to the payment of final legal costs associated with the litigation in Germany and the final billing with respect to the biennial royalty examination for the years 2009 and 2010 by the Trust's German accountants.

Report on Exploration and Drilling

The Trust's German consultant meets periodically with representatives of the operating companies to inquire about their planned and proposed drilling and geophysical work and other general matters. The following represents a summary of the Trust's German consultant's conversations with representatives of EMPG. The Trust is not able to confirm the accuracy of any of these responses. In addition, the operating companies are not required to take any of the actions outlined and, if they change their plans with respect to any such actions, they are not obligated to inform the Trust.

> Visbek Z-16a, a sour gas well, was successfully completed in 2012 and entered production with a good flow rate. However, after a few months of production, it suffered a severe casing collapse. EMPG intends to drill a new well parallel to the original well but has not yet set the date for the start of drilling. The final well that began drilling in 2012 was Goldenstedt Z-15a. This well had two purposes. The primary purpose is to serve as an infill well and improve the gas recovery factor in this area of the Zechstein reservoir. Production started in early 2013 at a higher flow rate than that initially reported. During the actual drilling, the depth of the well was increased by an additional 1,000 meters from the bottom of the Zechstein formation to penetrate the Carboniferous zone which lies beneath. This portion of the well was designated as Goldenstedt Z-15a (K) and was intended to explore reservoir conditions in the Carboniferous zone and delineate the gas bearing strata in this area. Test results for the Carboniferous zone indicated a high level of gas saturation as well as good porosity in the reservoir rock. The extension to the Carboniferous zone was then plugged. EMPG has indicated that this area of the Carboniferous zone may have further the development potential for an additional three wells.
>
> The moratorium on hydraulic fracking caused EMPG to shift its emphasis in 2012-2013 to infill drilling in the Zechstein zone within eastern Oldenburg. Three wells, Goldenstedt Z-25, Goldenstedt Z-34 and Visbek Z-9b, were planned for 2013. However, due to problems with the drilling rig schedule only one well was completed and just one other was begun. Goldenstedt Z-25 began drilling its second hole after problems encountered in the first drilling effort. The second hole was completed in January 2013 with production slated to begin in April 2013. For unexplained reasons the completion was delayed and production still has not begun. Visbek Z-9b, a sour gas well, was also delayed due to drilling rig availability and only began drilling in November 2013. Goldenstedt Z-34, originally scheduled to begin drilling in the fourth quarter of 2013, has been delayed and is currently scheduled to begin drilling in the second quarter of 2014.
>
> Beyond the one well delayed until 2014 due the drilling rig scheduling problems only one other well is scheduled for 2014. Hemmelte NW T-1, a western sweet gas well intended to exploit the Bunter zone, is scheduled to begin drilling in mid-2014. This is the first western well drilled in a number of years and, while it carries extra risk since it is

a wildcat well, it has the potential of opening up new reserves not previously known. The completion of this well may be further delayed since there are indications that the Bunter sandstone may require fracking.

Including Oythe Z-4, which was postponed from 2012, there are a total of six wells, four Carboniferous (Oythe Z-4 and Goldenstedt Z-24, Z-26 and Z-27) and two Zechstein (Kneheim Z-5a and Quaadmoor Z-4a), still in the portfolio for the period beyond 2014. The drilling of the four Carboniferous wells will depend upon the lifting of the moratorium on fracking, which according to EMPG's best estimate is unlikely prior to 2015. The drilling of Goldenstedt Z-26 and Z-27 are additionally dependent on the results of the drilling of Goldenstedt Z-24.

Critical Accounting Policies

The financial statements, appearing subsequently in this Report, present financial statement balances and financial results on a modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States ("GAAP basis"). Cash basis accounting is an accepted accounting method for royalty trusts such as the Trust. GAAP basis financial statements disclose income as earned and expenses as incurred, without regard to receipts or payments. The use of GAAP would require the Trust to accrue for expected royalty payments. This is exceedingly difficult since the Trust has very limited information on such payments until they are received and cannot accurately project such amounts. The Trust's cash basis financial statements disclose revenue when cash is received and expenses when cash is paid. The one modification of the cash basis of accounting is that the Trust accrues for distributions to be paid to unit owners (those distributions approved by the Trustees for the Trust). The Trust's distributable income represents royalty income received by the Trust during the period plus interest income less any expenses incurred by the Trust, all on a cash basis. In the opinion of the Trustees, the use of the modified cash basis provides a more meaningful presentation to unit owners of the results of operations of the Trust and presents to the unit owners a more accurate calculation of income and expenses for tax reporting purposes.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements.

Contractual Obligations

As shown below, the Trust had no contractual obligations as of October 31, 2013 other than the distribution announced on October 31, 2013 and payable to unit owners on November 27, 2013, as reflected in the statement of assets, liabilities and trust corpus.

Payments Due by Period

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Distributions payable to unit owners	$4,871,013	$4,871,013	$ 0	$ 0	$ 0

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This Report on Form 10-K may contain forward-looking statements intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Such statements address future expectations and events or conditions concerning the Trust. Many of these statements are based on information provided to the Trust by the operating companies or by consultants using public information sources. These statements are subject to certain risks and uncertainties that could cause actual results to differ materially from those anticipated in any forward-looking statements. These include:

- risks and uncertainties concerning levels of gas production and gas sale prices, general economic conditions and currency exchange rates;
- the ability or willingness of the operating companies to perform under their contractual obligations with the Trust;
- potential disputes with the operating companies and the resolution thereof; and
- the risk factors set forth above under Item 1A of this Report.

All such factors are difficult to predict, contain uncertainties that may materially affect actual results, and are generally beyond the control of the Trust. New factors emerge from time to time and it is not possible for the Trust to predict all such factors or to assess the impact of each such factor on the Trust. Any forward-looking statement speaks only as of the date on which such statement is made, and the Trust does not undertake any obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made.

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

The Trust does not engage in any trading activities with respect to possible foreign exchange fluctuations. The Trust does not use any financial instruments to hedge against possible risks related to foreign exchange fluctuations. The market risk is negligible because standing instructions at the Trust's German bank require the bank to process conversions and transfers of royalty payments as soon as possible following their receipt. The Trust does not engage in any trading activities with respect to commodity price fluctuations.

Item 8. Financial Statements and Supplementary Data.

NORTH EUROPEAN OIL ROYALTY TRUST

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Board of Trustees and the Unit Owners of
North European Oil Royalty Trust

We have audited the accompanying statements of assets, liabilities and trust corpus of North European Oil Royalty Trust (the "Trust") as of October 31, 2013 and 2012, and the related statements of revenue collected and expenses paid, undistributed earnings, and changes in cash and cash equivalents for each of the years in the three-year period ended October 31, 2013. The Trust's management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

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

As described in Note 1, these financial statements have been prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the Trust as of October 31, 2013 and 2012, its revenue collected and expenses paid, its undistributed earnings, and changes in its cash and cash equivalents for each of the years in the three-year period ended October 31, 2013, on the basis of accounting described in Note 1.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust's internal control over financial reporting as of October 31, 2013, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated December 30, 2013 expressed an unqualified opinion.

/s/ WeiserMazars LLP
New York, NY
December 30, 2013

NORTH EUROPEAN OIL ROYALTY TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS (NOTE 1)

OCTOBER 31, 2013 AND 2012

ASSETS	2013	2012
Current assets - - Cash and cash equivalents	$ 4,918,490	$ 4,778,199
Producing gas and oil royalty rights, net of amortization (Notes 1 and 2)	1	1
Total Assets	$ 4,918,491	$ 4,778,200
LIABILITIES AND TRUST CORPUS		
Current liabilities - - Distributions to be paid to unit owners, paid November 2013 and 2012	$ 4,871,013	$ 4,687,200
Trust corpus (Notes 1 and 2)	1	1
Undistributed earnings	47,477	90,999
Total Liabilities and Trust Corpus	$ 4,918,491	$ 4,778,200

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

NORTH EUROPEAN OIL ROYALTY TRUST

STATEMENTS OF REVENUE COLLECTED AND EXPENSES PAID (NOTE 1)

FOR THE FISCAL YEARS ENDED OCTOBER 31, 2013, 2012 AND 2011

	2013	2012	2011
German gas, sulfur and oil royalties received	$ 21,546,298	$ 23,672,808	$ 25,148,523
Interest income	25,363	40,156	26,233
Trust Income	21,571,661	23,712,964	25,174,756
Non-related party expenses	(857,334)	(982,700)	(872,233)
Related party expenses (Note 3)	(79,021)	(120,303)	(106,616)
Trust Expenses	(936,355)	(1,103,003)	(978,849)
Net Income	$ 20,635,306	$ 22,609,961	$ 24,195,907
Net income per unit	$ 2.25	$ 2.46	$ 2.63
Distributions per unit paid or to be paid to unit owners	$ 2.25	$ 2.46	$ 2.63

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

NORTH EUROPEAN OIL ROYALTY TRUST

STATEMENTS OF UNDISTRIBUTED EARNINGS (NOTE 1)

FOR THE FISCAL YEARS ENDED OCTOBER 31, 2013, 2012 AND 2011

	2013	2012	2011
Balance, beginning of year	$ 90,999	$ 89,889	$ 65,234
Net income	20,635,306	22,609,961	24,195,907
	20,726,305	22,699,850	24,261,141
Less:			
Current year distributions paid or to be paid to unit owners	20,678,828	22,608,851	24,171,252
Balance, end of year	$ 47,477	$ 90,999	$ 89,889

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

NORTH EUROPEAN OIL ROYALTY TRUST

STATEMENTS OF CHANGES IN CASH AND CASH EQUIVALENTS (NOTE 1)

FOR THE FISCAL YEARS ENDED OCTOBER 31, 2013, 2012 AND 2011

	2013	2012	2011
Sources of Cash and Cash Equivalents:			
German gas, sulfur and oil royalties received	$ 21,546,298	$ 23,672,808	$ 25,148,523
Interest income	25,363	40,156	26,233
	21,571,661	23,712,964	25,174,756
Uses of Cash and Cash Equivalents:			
Payment of Trust expenses	936,355	1,103,003	978,849
Distributions paid	20,495,015	23,803,628	23,436,006
.	21,431,370	24,906,631	24,414,855
Net increase (decrease) in cash and cash equivalents during the year	140,291	(1,193,667)	759,901
Cash and cash equivalents, beginning of year	4,778,199	5,971,866	5,211,965
Cash and cash equivalents, end of year	$ 4,918,490	$ 4,778,199	$ 5,971,866

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

NORTH EUROPEAN OIL ROYALTY TRUST

NOTES TO FINANCIAL STATEMENTS

OCTOBER 31, 2013, 2012 AND 2011

(1) Summary of significant accounting policies:

Basis of accounting -

The accompanying financial statements of North European Oil Royalty Trust (the "Trust") are prepared in accordance with the rules and regulations of the SEC. Financial statement balances and financial results are presented on a modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States ("GAAP basis"). On a modified cash basis, revenue is earned when cash is received and expenses are incurred when cash is paid. GAAP basis financial statements disclose revenue as earned and expenses as incurred, without regard to receipts or payments. The modified cash basis of accounting is utilized to permit the accrual for distributions to be paid to unit owners (those distributions approved by the Trustees for the Trust). The Trust's distributable income represents royalty income received by the Trust during the period plus interest income less any expenses incurred by the Trust, all on a cash basis. In the opinion of the Trustees, the use of the modified cash basis of accounting provides a more meaningful presentation to unit owners of the results of operations of the Trust.

Producing gas and oil royalty rights -

The rights to certain gas and oil royalties in Germany were transferred to the Trust at their net book value by North European Oil Company (the "Company") (see Note 2). The net book value of the royalty rights has been reduced to one dollar ($1) in view of the fact that the remaining net book value of royalty rights is *de minimis* relative to annual royalties received and distributed by the Trust and does not bear any meaningful relationship to the fair value of such rights or the actual amount of proved producing reserves.

Federal and state income taxes -

The Trust, as a grantor trust, is exempt from federal income taxes under a private letter ruling issued by the Internal Revenue Service. The Trust has no state income tax obligations.

Cash and cash equivalents -

Cash and cash equivalents are defined as amounts deposited in bank accounts and amounts invested in certificates of deposit and U. S. Treasury bills with original maturities generally of three months or less from the date of purchase. The investment options available to the Trust are limited in accordance with specific provisions of the Trust Agreement. As of October 31, 2013, the uninsured amounts held in the Trust's U.S. bank accounts were approximately $4,660,000. In addition, approximately $11,600 was held in the Trust's German account at October 31, 2013.

Net income per unit -

Net income per unit is based upon the number of units outstanding at the end of the period. As of October 31, 2013, 2012 and 2011, there were 9,190,590 units of beneficial interest outstanding.

New accounting pronouncements -

The Trust is not aware of any recently issued, but not yet effective, accounting standards that would be expected to have a significant impact on the Trust's financial position or results of operations.

(2) Formation of the Trust:

The Trust was formed on September 10, 1975. As of September 30, 1975, the Company was liquidated and the remaining assets and liabilities of the Company, including its royalty rights, were transferred to the Trust. The Trust, on behalf of the owners of beneficial interest in the Trust, holds overriding royalty rights covering gas and oil production in certain concessions or leases in the Federal Republic of Germany. These rights are held under contracts with local German exploration and development subsidiaries of ExxonMobil Corp. and the Royal Dutch/Shell Group. Under these contracts, the Trust receives various percentage royalties on the proceeds of the sales of certain products from the areas involved. At the present time, royalties are received for sales of gas well gas, oil well gas, crude oil, distillate and sulfur.

(3) Related party transactions:

John R. Van Kirk, the Managing Director of the Trust, provides office space and services to the Trust at cost. For such office space and services, the Trust reimbursed the Managing Director $25,602, $27,095 and $29,039 in fiscal 2013, 2012 and 2011, respectively.

Lawrence A. Kobrin, a Trustee of the Trust, is a Senior Counsel at Cahill Gordon & Reindel LLP, which serves as counsel to the Trust. For legal services, the Trust paid Cahill Gordon & Reindel LLP $53,419, $93,208 and $77,577 in fiscal 2013, 2012 and 2011, respectively.

(4) <u>Employee benefit plan:</u>

The Trust has established a savings incentive match plan for employees (SIMPLE IRA) that is available to both employees of the Trust, one of whom is the Managing Director. The Trustees authorized the making of contributions by the Trust to the accounts of employees, on a matching basis, of up to 3% of cash compensation paid to each such employee for the 2013, 2012 and 2011 calendar years.

(5) <u>Legal matters:</u>

The Trust is not a party to any pending legal proceedings. The previous litigation commenced by the Trust in Germany against the operating companies (See 2011 Annual Report on Form 10-K) was concluded after an adverse district court ruling in May 2012, from which the Trust and its co-plaintiff, after consultation with their local counsel, determined not to appeal.

(6) Quarterly results (unaudited):

The tables below summarize the quarterly results and distributions of the Trust for the fiscal years ended October 31, 2013 and 2012**:**

Fiscal 2013 by Quarter and Year

	First	Second	Third	Fourth	Year
Royalties received	$5,795,834	$6,048,364	$4,687,351	$5,014,749	$21,546,298
Net income	$5,473,010	$5,842,545	$4,459,386	$4,860,365	$20,635,306
Net income per unit	$0.60	$0.64	$0.49	$0.53	$2.25
Distributions paid or to be paid	$5,422,448	$5,881,978	$4,503,389	$4,871,013	$20,678,828
Distributions per unit paid or to be paid to unit owners	$0.59	$0.64	$0.49	$0.53	$2.25

Fiscal 2012 by Quarter and Year

	First	Second	Third	Fourth	Year
Royalties received	$6,538,261	$6,441,635	$5,846,833	$4,846,079	$23,672,808
Net income	$6,079,264	$6,262,114	$5,589,094	$4,679,489	$22,609,961
Net income per unit	$0.66	$0.68	$0.61	$0.51	$2.46
Distributions paid or to be paid	$6,065,789	$6,249,601	$5,606,261	$4,687,200	$22,608,851
Distributions per unit paid or to be paid to unit owners	$0.66	$0.68	$0.61	$0.51	$2.46

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

None.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

The Trust maintains disclosure controls and procedures that are designed to ensure that information required to be disclosed by the Trust is recorded, processed, summarized, accumulated and communicated to its management, which consists of the Managing Director, to allow timely decisions regarding required disclosure, and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. The Managing Director has performed an evaluation of the effectiveness of the design and operation of the Trust's disclosure controls and procedures as of October 31, 2013. Based on that evaluation, the Managing Director concluded that the Trust's disclosure controls and procedures were effective as of October 31, 2013.

Internal Control over Financial Reporting

Part A. Management's Report on Internal Control over Financial Reporting

The Trust's management is responsible for establishing and maintaining adequate internal control over financial reporting (as such term is defined in Exchange Act Rule 13a-15(f)) for the Trust. There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time. Management has evaluated the Trust's internal control over financial reporting as of October 31, 2013. This assessment was based on criteria for effective internal control over financial reporting described in the standards promulgated by the Public Company Accounting Oversight Board and in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Trust's internal control over financial reporting was effective as of October 31, 2013. Management's assessment of the effectiveness of our internal control over financial reporting as of October 31, 2013 has been audited by WeiserMazars LLP, the Trust's independent auditor, as stated in their report which follows.

Part B. Attestation Report of Independent Registered Public Accounting Firm

Report of Independent Registered Public Accounting Firm on
Internal Control over Financial Reporting

To the Board of Trustees and the Unit Owners
of North European Oil Royalty Trust

We have audited North European Oil Royalty Trust's (the "Trust") internal control over financial reporting as of October 31, 2013, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Trust's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Trust's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

The Trust's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. The Trust's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Trust are being made only in accordance with authorizations of management and Trustees of the Trust; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Trust's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of October 31, 2013, based on criteria established in *Internal Control—Integrated Framework* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the statements of assets, liabilities and trust corpus as of October 31, 2013 and 2012, and the related statements of revenue collected and expenses paid, undistributed earnings, and changes in cash and cash equivalents for each of the years in the three-year period ended October 31, 2013 and our report dated December 30, 2013 expressed an unqualified opinion thereon.

/s/ WeiserMazars LLP
New York, NY
December 30, 2013

Part C. Changes in Internal Control over Financial Reporting

There have been no changes in the Trust's internal control over financial reporting that occurred during the fourth quarter of fiscal 2013 that have materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Except as set forth below, the information required by this item will be contained in the Trust's definitive Proxy Statement for its Annual Meeting of Unit Owners to be held on February 11, 2014, to be filed pursuant to Section 14 of the Securities Exchange Act of 1934, and is incorporated herein by reference.

Code of Ethics

The Trustees have adopted a Code of Conduct and Business Ethics (the "Code") for the Trust's Trustees and employees, including the Managing Director. The Managing Director serves the roles of principal executive officer and principal financial and accounting officer. A copy of the Code is available without charge on request by writing to the Managing Director at the office of the Trust. The Code is also available at the Trust's website, www.neort.com.

All Trustees and employees of the Trust are required to read and sign a copy of the Code annually. No waivers or exceptions to the Code have been granted since the adoption of the Code. Any amendments or waivers to the Code, to the extent required, will be disclosed in a Form 8-K filing of the Trust after such amendment or waiver.

Item 11. Executive Compensation.

The information required by this item will be contained in the Trust's definitive Proxy Statement for its Annual Meeting of Unit Owners to be held on February 11, 2014, to be filed pursuant to Section 14 of the Securities Exchange Act of 1934, and is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

The information required by this item will be contained in the Trust's definitive Proxy Statement for its Annual Meeting of Unit Owners to be held on February 11, 2014, to be filed pursuant to Section 14 of the Securities Exchange Act of 1934, and is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

The information required by this item will be contained in the Trust's definitive Proxy Statement for its Annual Meeting of Unit Owners to be held on February 11, 2014, to be filed pursuant to Section 14 of the Securities Exchange Act of 1934, and is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services.

The information required by this item will be contained in the Trust's definitive Proxy Statement for its Annual Meeting of Unit Owners to be held on February 11, 2014, to be filed pursuant to Section 14 of the Securities Exchange Act of 1934, and is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) The following is a list of the documents filed as part of this Report:

1. Financial Statements

Index to Financial Statements for the Fiscal Years Ended October 31, 2013, 2012 and 2011

Report of Independent Registered Public Accounting Firm

Statements of Assets, Liabilities and Trust Corpus as of October 31, 2013 and 2012

Statements of Revenue Collected and Expenses Paid for the Fiscal Years Ended October 31, 2013, 2012 and 2011

Statements of Undistributed Earnings for the Fiscal Years Ended October 31, 2013, 2012 and 2011

Statements of Changes in Cash and Cash Equivalents for the Fiscal Years Ended October 31, 2013, 2012 and 2011

Notes to Financial Statements

2. Exhibits

The Exhibit Index following the signature page lists all exhibits filed with this Report or incorporated by reference.

Signatures

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

NORTH EUROPEAN OIL ROYALTY TRUST

Dated: December 30, 2013

By: /s/ John R. Van Kirk
John R. Van Kirk, Managing Director
and Principal Accounting Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Dated: December 30, 2013

/s/ Robert P. Adelman
Robert P. Adelman, Managing Trustee

Dated: December 30, 2013

/s/ Samuel M. Eisenstat
Samuel M. Eisenstat, Trustee

Dated: December 30, 2013

/s/ Lawrence A. Kobrin
Lawrence A. Kobrin, Trustee

Dated: December 30, 2013

/s/ Willard B. Taylor
Willard B. Taylor, Trustee

Dated: December 30, 2013

/s/ Rosalie J. Wolf
Rosalie J. Wolf, Trustee

Dated: December 30, 2013

/s/ John R. Van Kirk
John R. Van Kirk, Managing Director
and Principal Accounting Officer

Exhibit Index

Exhibit		Page
(3.1)	North European Oil Royalty Trust Agreement, dated September 10, 1975, as amended through February 13, 2008 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K, filed February 15, 2008 (File No. 0-8378)).	
(3.2)	Amended and Restated Trustees' Regulations, amended and restated as of October 31, 2007 (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K, filed November 2, 2007 (File No. 0-8378)).	
(10.1)	Agreement with OEG, dated April 2, 1979, exhibit to Current Report on Form 8-K filed May 11, 1979 (incorporated by reference as Exhibit 1 to Current Report on Form 8-K, filed May 11, 1979 (File No. 0-8378)).	
(10.2)	Agreement with Mobil Oil, A.G. concerning sulfur royalty payment, dated March 30, 1979 (incorporated by reference to Exhibit 3 to Current Report on Form 8-K, filed May 11, 1979 (File No. 0-8378)).	
(21)	There are no subsidiaries of the Trust.	
(31)	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	49
(32)	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	51
(99.1)	Calculation of Cost Depletion Percentage for the 2013 Calendar Year Based on the Estimate of Remaining Proved Producing Reserves in the Northwest Basin of the Federal Republic of Germany as of October 1, 2013 prepared by Ralph E. Davis Associates, Inc.	52
(99.2)	Order Approving Settlement signed by Vice Chancellor Jack Jacobs of the Delaware Court of Chancery (incorporated by reference as Exhibit 99.2 to Current Report on Form 8-K, filed February 26, 1996).	

Exhibit 31

Certification of Chief Executive Officer and Chief Financial Officer
Pursuant to Section 302
of the Sarbanes-Oxley Act of 2002

I, John R. Van Kirk, certify that:

1. I have reviewed this Annual Report on Form 10-K of North European Oil Royalty Trust;

2. Based on my knowledge, this 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) 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 report is being prepared; and

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under my supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles; and

    c) 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

d) 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 (the registrant's fourth fiscal quarter in the case of an annual report) 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 of internal control over financial reporting, to the registrant's auditors and to the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

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 management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: December 30, 2013

/s/ John R. Van Kirk
John R. Van Kirk
Managing Director
Chief Executive Officer
and Chief Financial Officer

Exhibit 32

Certification of Chief Executive Officer and
Chief Financial Officer
Pursuant to Section 906
of the Sarbanes-Oxley Act of 2002

Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Chapter 63, Title 18 U.S.C. §1350(a) and (b)), the undersigned hereby certifies that the Annual Report on Form 10-K for the period ended October 31, 2013 of North European Oil Royalty Trust ("Trust") fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934 and that the information contained in such Report fairly presents, in all material respects, the financial condition and results of operations of the Trust.

Dated: December 30, 2013

/s/ John R. Van Kirk
John R. Van Kirk
Managing Director
Chief Executive Officer
and Chief Financial Officer

North European Oil Royalty Trust

Calculation of Cost Depletion Percentage
For 2013 Calendar Year
Based On The
Estimate of Remaining Proved Producing
Reserves in the Northwest Basin Of The
Federal Republic of Germany
As Of October 1. 2013

RALPH E. DAVIS ASSOCIATES, INC.
HOUSTON, TEXAS

Table of Contents

RALPH E. DAVIS
ASSOCIATES, INC.

December 13, 2013

The Trustees of
North European Oil Royalty Trust
P. O. Box 456
Red Bank, New Jersey 07701

Ref: North European Oil Royalty Trust
Calculation of the Cost Depletion Percentage
For the Calendar Year 2013

Trustees:

In accordance with the request of the Trustees of North European Oil Royalty Trust (the “Trustees”), the firm of Ralph E. Davis Associates, Inc. (“Davis Associates”) of Houston, Texas has performed the calculations necessary to derive the cost depletion percentage for the 2013 calendar year. The cost depletion percentage was prepared for use by individual Trust unit owners in their tax preparations. In order to perform the calculation of the cost depletion percentage we were further requested by the Trustees to prepare a report of the estimated remaining proved producing reserves attributable to the overriding royalty interests of North European Oil Royalty Trust (the "Trust") in the Northwest German Basin of the Federal Republic of Germany with an effective date of October 1, 2013.

We have reviewed all available information with respect to 100% of the Trust’s proved developed properties utilized in the calculation of the cost depletion percentage as discussed later in this report. It is our opinion that these properties represent all of the Trust’s assets that may be classified as proved for this purpose as per the Securities and Exchange Commission directives as detailed later in this report.

The reserves associated with this review have been classified in accordance with the definitions of the Securities and Exchange Commission as found in Part 210—Form and Content of and Requirements for Financial Statements, Securities Act of 1933, Securities Exchange Act of 1934, Public Utility Holding Company Act of 1935, Investment Company Act of 1940, Investment Advisers Act of 1940, and Energy Policy and Conservation Act of 1975, under Rules of General Application § 210.4-10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975.

The proved producing reserves are as of October 1, 2013 and the reported sales are for the twelve month period ending September 30, 2013. The use of the period ending September 30, 2013 is consistent with prior years and allows the timely calculation of the royalty reserves and the cost depletion percentage for the calendar year. Throughout this report the unit price used for crude oil, condensate, natural gas and sulfur is based upon the appropriate price in effect for each of the twelve months during fiscal 2013 and averaged for the period.

Based on the results of our calculation of estimated remaining proved producing reserves contained in the first part of this report, we have performed the calculations necessary to derive the cost depletion percentage for the 2013 calendar year. As detailed in Attachment B, the cost depletion percentage for the 2013 calendar year for Trust unit owners is equal to 10.6104 % of their cost base as of January 1, 2013.

Discussion

The scope of this study was to review limited information we were able to compile and to prepare an estimate of the proved producing reserves attributable to the interests of the Trust from which the cost depletion percentage could be calculated. We prepared reserve estimates using acceptable evaluation principals for each source. These estimates were based in large part on the limited information supplied by the operator of the relevant properties.

The quantities presented herein are estimated reserves of oil, natural gas, natural gas liquids and sulfur that geologic and engineering data demonstrate can be recovered from known reservoirs under current economic conditions with reasonable certainty.

Description of Holdings

The Trust holds various overriding royalty rights on sales of gas, sulfur and oil from certain concessions and leases in the Federal Republic of Germany. The Oldenburg concession (1,398,000 acres), covering virtually the entire former Grand Duchy of Oldenburg and located in the federal state of Lower Saxony, is held by Oldenburgische Erdolgesellschaft ("OEG"). OEG in turn is owned by Mobil Erdgas-Erdol GmbH ("Mobil Erdgas"), the German subsidiary of ExxonMobil Corp. and by BEB Erdgas und Erdol GmbH ("BEB"), a joint venture of ExxonMobil Corp. and the Royal Dutch/Shell Group of Companies. As a result by direct and indirect ownership, ExxonMobil Corp. owns two-thirds of OEG and the Royal Dutch/Shell Group owns one-third of OEG.

The Oldenburg concession is the major source of royalty income for the Trust. All proved producing reserves within the Oldenburg concession are covered by this report. Although the Trust has interests in other producing areas, reserves and net sales for these areas are no longer used in the calculation of the annual cost depletion percentage. The exclusion of these reserves does not have a material effect on the calculation of the cost depletion percentage. We will continue to monitor the quarterly statements and, if increases are noted that could materially add reserves to the Trust, we will resume estimating future reserves.

In 2002 Mobil Erdgas and BEB formed a new company ExxonMobil Production Deutschland GmbH to carry out all exploration, drilling and production within the Oldenburg concession. All sales activities are still handled by either Mobil Erdgas or BEB.

a) Under one set of rights covering the western part of the Oldenburg concession (approximately 662,000 acres), the Trust receives a royalty payment of 4% on gross receipts from sales by Mobil Erdgas of gas well gas, oil well gas, crude oil and condensate (the "Mobil Agreement"). Under the Mobil Agreement there is no deduction of costs prior to the calculation of royalties from gas well gas or oil well gas, which together account for approximately 98% of all the royalties under said agreement.

b) Under another series of rights covering the entire Oldenburg concession and pursuant to an agreement with OEG, the Trust receives royalties at the rate of 0.6667% on gross receipts from sales of gas well gas, oil well gas, crude oil, condensate and sulfur (removed during the processing of sour gas) less a certain allowed deduction of costs (the "OEG Agreement"). Under the OEG Agreement, 50% of the field handling, treatment and transportation costs as reported for state royalty purposes are deducted from gross sales receipts prior to the calculation of the royalty to be paid to the Trust. Sulfur is a by-product of gas production and is not considered in the computation of total cost depletion.

c) The Trust is also entitled to receive from Mobil Erdgas a 2% royalty payment on gross receipts from sales of sulfur obtained as a by-product of sour gas produced from the western part of Oldenburg. However, the payment of the sulfur royalty is provisional on whether Mobil Erdgas' selling price meets or exceeds the indexed base price. The selling price had been below the indexed base price for more than ten years, but beginning in the second quarter of fiscal year 2008 the price for sulfur exceeded the indexed base price. The average selling price for sulfur exceeded the indexed base price, and the Trust received sulfur royalties under the Mobil Agreement, during the second, third and fourth quarters of fiscal 2008, the first quarter of fiscal 2009, the third quarter of fiscal 2010, the second, third and fourth quarters of fiscal 2011 and for all four quarters of fiscal 2012 and fiscal 2013. Sulfur is a by-product of gas production and is not considered in the computation of total cost depletion.

Oldenburg Area - Sales and Reserves

The Trust's royalty income comes primarily from the Oldenburg area. Gas production accounts for the majority of the income; however, the hydrogen sulfide in much of the gas produced necessitates its removal before the gas can be sold. At the Grossenkneten desulfurization plant, the hydrogen sulfide in sour gas is removed. Following earlier renovations and improvements to the plant, the plant's present input capacity stands at 620 million cubic feet ("MMcf") per day. A second desulfurization plant, Norddeutsche Erdgas Aufbereitungs GmbH ("NEAG") remains connected by pipeline with the transportation system of the Oldenburg concession. Only four Oldenburg fields are connected to NEAG. As recently as 2007 and 2008, respectively, only 7.48% and 4.07% of the total amount of Oldenburg sour gas was processed at NEAG. We have received no information with respect to usage beyond 2008.

Total Sales

During the twelve months ending September 30, 2013, total sales for the Oldenburg area were as follows:

	WEST	EAST	TOTAL
Gas Well Gas-MMcf	33,820	69,430	97,250
Oil Well Gas-MMcf	19	15	34
Oil & Condensate-Barrels	96,266	43,050	139,316
Sulfur-Short Tons	208,066	421,086	629,152

Gross Reserves

Estimated gross remaining proved producing reserves attributable to the total Oldenburg area as of October 1, 2013 are as follows:

	WEST	EAST	TOTAL
Gas Well Gas-MMcf	281,441	564,375	845,816
Oil Well Gas-MMcf	160	80	240
Oil & Condensate-Barrels	1,123,485	488,066	1,611,511
Sulfur-Short Tons	1,109,210	5,896,571	7,508,122

Net Reserves

To present an accurate picture of estimated proved producing reserves net to the Trust, the gross reserve figures outlined above must be modified by the impact of the different royalty rates in effect in the Oldenburg concession. A comparison of the Trust's overriding royalty rates in both the western and eastern areas of Oldenburg is as follows:

		WEST	EAST
Mobil Erdgas			
	Gas & Oil	4%	0%
	Sulfur	2%	0%
BEB			
	Gas & Oil	0.6667% (1)	0.6667% (1)
	Sulfur	0.6667% (1)	0.6667% (1)

(1) Prior to the calculation of royalties, 50% of costs as reported for state royalty purposes are deducted.

The application of these royalty rates to the estimated gross remaining proved producing reserves attributable to the western and eastern Oldenburg areas yields the combined estimated proved producing reserves net to the Trust. The Trust's estimated remaining net proved producing reserves as of October 1, 2013 and net sales for the twelve month period ending September 30, 2013 are as follows:

	Reserves	Sales
Gas Well Gas; MMcf	16,280	1,968
Oil Well Gas; MMcf	8	1
Oil & Condensate; Barrels	65,130	4,713
Sulfur; Short Tons	54,928	8,009

A summary of net proved producing reserves by product and a five year history of net sales attributable to the royalty interests of the Trust are presented in Attachment A.

Limitations of Available Data

The reserves considered in this report are defined as proved producing reserves. Proved producing reserves are limited to those quantities which can be expected to be recoverable commercially from known reservoirs at current prices and costs, under existing regulatory practices and with existing conventional equipment and operating methods. Proved producing reserves do not include either proved developed non-producing reserves or any class of probable reserves.

The estimate of reserves included in this report is based primarily upon production history or analogy with wells in the area producing from the same or similar formations. In addition to individual well production history, geological and well test information, when available, were utilized in the evaluation.

The reserves included in this report are estimates only and should not be construed as being exact quantities. The accuracy of the estimates is dependent upon the quality of available data and upon the independent geological and engineering interpretation of that data. The quantities presented herein are estimated reserves of hydrocarbons and produced products that geologic and engineering data demonstrate can be recovered from known reservoirs under current economic conditions with reasonable certainty. Reserve estimates presented in this report are calculated using acceptable methods and procedures and are believed to be appropriate and reasonable; however, future reservoir performance may justify revision of these estimates.

For the purpose of this report, estimated reserves are scheduled for recovery primarily on the basis of actual producing rates or appropriate well test information. They were prepared giving consideration to engineering and geological data, anticipated producing mechanisms, the number and types of completions, as well as past performance of analogous reservoirs. Individual well production histories were analyzed and an appropriate daily producing rate was utilized for each individual well in the preparation of a forecast of future producing rates until an anticipated economic limit.

The estimates of reserves and the forecasted rates of production may be subject to regulation by various agencies, changes in market demand or other factors. Consequently, the volumes of reserves recovered and the actual rates of recovery may vary from the estimates included herein.

The Trust, as an overriding royalty interest owner, does not receive proprietary data from the various operators on producing wells. Data, such as logs, core analysis, reservoir tests, pressure tests, gas analyses, geologic maps, and individual well production histories on all of the wells which are used in volumetric and material balance type reserve estimates, are not available to the Trust. The lack of such data increases the inherent uncertainties of our reserve estimate.

The Trust receives quarterly statements from the operators that report production, sales and revenue data. Utilizing the same procedures as in prior years, this information plus published information received from W.E.G. (a German organization comparable to the American Petroleum Institute or the American Gas Association) has been used to prepare this annual report. In addition, the Trust retains a part-time consultant in Germany who is familiar with the German petroleum industry in general and the operating companies in particular. His periodic reports and communications were considered in the preparation of this report.

We believe that reserve estimates prepared using all the available data are appropriate and sufficient for the calculation of the cost depletion percentage. However, due to the limitations of available data, this estimate of reserves cannot have the same degree of accuracy that an estimate of reserves prepared using all pertinent data would have. Our experience in the evaluation of reserves using such limited data, including twenty two (22) years of experience working for the Trust, compensates somewhat for the limitations of available data.

The data in the reports received by the Trust is in metric tons and cubic meters. The following Metric to English Unit conversion factors were used:

Gas:	37.25 cubic feet per cubic meter at 14.7 psia and 60 degrees Fahrenheit
Oil:	7.23 barrels per metric ton
Sulfur:	1.1 short tons per metric ton

Calculation of Cost Depletion Percentage

The categories of proved producing reserves considered in the calculation of the cost depletion percentage are oil, oil well gas, and gas well gas. Sulfur is a by-product of gas production and is not considered in the computation of total cost depletion percentage.

For each category of reserves, a product base was established for the Trust as of January 1, 1976. Through the use of these product bases, we can account for the relative size of each of these categories of reserves and the corresponding impact on the calculation of the cost depletion percentage. The product base for each category of proved producing reserves is reduced annually by an adjustment that is calculated by multiplying the product base at the beginning of the current year by the depletion factor for that category of reserves. The depletion factor for each category of reserves is the ratio of the relevant net sales during the current year to the corresponding adjusted net proved producing reserves at the beginning of the current year.

Significant items in the cost depletion percentage calculation that appear on Attachment B as specific item numbers, shown in parentheses and their sources are as follows:

> The adjusted estimated net proved producing reserves as of 10/1/12 Line (3) is obtained by adding the estimated remaining net proved producing reserves as of 10/1/12 Line (1) and the adjustments to reserves during the period Line (2). Therefore Line (3) = Line (1) + Line (2).
>
> The depletion factor Line (6) for each category of proved producing reserves is obtained by dividing the relevant net sales Line (4) by the corresponding adjusted estimated net proved producing reserves as of 10/1/12 Line (3). Therefore Line (6) = Line (4) / Line (3).
>
> The product base for each category of proved producing reserves as of 1/1/12 Line (7) and the adjustment taken during 2012 Line (8) were obtained from the previous year's report. The product base as of 1/1/13 Line (9) forms the initial starting point for the calculation of the cost depletion percentage for the 2013 tax year. The product base for 1/1/13 Line (9) then is Line (7) - Line (8).

The adjustment to the product base for each category of proved producing reserves Line (10) is used to reduce the product base as of the beginning of each year. This adjustment is the product of the depletion factor for each category of proved producing reserves Line (6) multiplied by the corresponding product base as of 1/1/13 Line (9). Therefore Line (10) = Line (6) x Line (9).

The cost depletion percentage Line (11) then is the sum of the adjustment to the product base of each category of proved producing reserves [Sum Line (10)] divided by the sum of the product base for each category as of 1/1/13 [Sum Line (9)]. Therefore Line (11) = [Sum Line (10)] / [Sum Line (9)].

The cost depletion percentage represents the total allowable cost depletion for the 2013 calendar year for the Trust's unit owners, expressed as a percentage of their cost base as of January 1, 2013.

Neither Ralph E. Davis Associates, Inc. nor any of its employees have any interest in the subject properties and neither the employment to make this study and calculation nor our compensation is contingent on our estimate of reserves or the results of our calculation.

We appreciate the opportunity to be of service to you in this matter and will be glad to address any questions or inquiries you may have.

Sincerely yours,
RALPH E. DAVIS ASSOCIATES, INC.

STATE OF TEXAS
ALLEN C. BARRON
49284
LICENSED
PROFESSIONAL ENGINEER

Allen C. Barron, P.E.
President

Attachment A

North European Oil Royalty Trust
Reserve Summary and Five Year Net Sales History

Estimated Net Proved Producing Reserves
As of October 1, 2013

OLDENBURG			
Gas Well Gas MMcf	Oil Well Gas MMcf	Oil/Cond. Barrels	Sulfur Short Tons
16,280	8	65,130	91,360 (1)

Five Year Net Sales Summary
12 Months Ending September 30, 2013

	OLDENBURG			
	Gas Well Gas MMcf	Oil Well Gas MMcf	Oil/Cond. Barrels	Sulfur Short Tons
2013	1,968	1	4,713	8,009 (1)
2012	2,174	1	3,897	8,997 (2)
2011	2,453	1	4,380	8,243 (3)
2010	2,421	2	3,916	6,937 (4)
2009	2,816	2	4,828	8,780 (5)

(1) Royalty payments under the Mobil Erdgas sulfur royalty representing all four quarters of fiscal 2013 were received.

(2) Royalty payments under the Mobil Erdagas sulfur royalty representing all four quarters of fiscal 2012 were received.

(3) With the exception of the fourth quarter of fiscal 2011, payments were received under the Mobil Erdgas sulfur royalty.

(4) With the exception of the third quarter of fiscal 2010, no payments were received under the Mobil Erdgas sulfur royalty.

(5) With the exception of the first quarter of fiscal 2009, no payments were received under the Mobil Erdgas sulfur royalty.

Attachment B

Northern European Oil Royalty Trust
Calculation of Total Cost Depletion Percentage
For The Year Ending December 31, 2013

	OLDENBURG		
	Gas Well Gas MMCF	Oil Well Gas MMCF	Oil Barrels
Neort Net Reserves (Million Cubic Feet of Gas and Barrels of Oil)			
1. Estimated remaining net proved producing reserves as of 10-1-12	19,417	8	58,741
2. Adjustments to reserves during period	-1,169	1	11,102
3. Adjusted estimated net proved producing reserves as of 10-1-12	18,248	9	69,843
4. Net sales from 10-1-12 to 9-30-13	1,968	1	4,713
5. Estimated remaining net proved producing reserves as of 10-1-13	16,280	8	65,130
Reserve Depletion Factor			
6. Depletion factor	0.10785	0.11111	0.06748
Neort Weighted Product Base Allocation			
7. Product base as of 1-1-12	3.81492	0.00253	0.16547
8. Less adjustments taken during 2012	0.38412	0.00028	0.01029
9. Product base as of 1-1-13	3.43080	0.00225	0.15518
10. 2013 Adjustment to product base	0.37000	0.00025	0.01047

11. Cost depletion percentage for 2013 calendar year for Trust unit owners is equal to 10.6104 percent of their 1-1-2013 cost base.

Footnotes:

Line (1) from reserves review as of 10-1-12
Line (2) from reserves review as of 10-1-13
Line (3) = Line (1) + Line (2)
Line (4) from BEB and Mobil Erdgas statements
Line (5) from reserves review as of 10-1-13
Line (6) = Line (4) / Line (3)

Line (7) from 2012 depletion calculations
Line (8) from 2012 depletion calculations
Line (9) = Line (7) - Line (8)
Line (10) = Line (9) x Line (6)
Line (11) = Sum Line (10) / Sum Line (9)

Securities and Exchange Commission
Definitions of Reserves

The following information is taken from the United States Securities and Exchange Commission:

PART 210—FORM AND CONTENT OF AND REQUIREMENTS FOR FINANCIAL STATEMENTS, SECURITIES ACT OF 1933, SECURITIES EXCHANGE ACT OF 1934, PUBLIC UTILITY HOLDING COMPANY ACT OF 1935, INVESTMENT COMPANY ACT OF 1940, INVESTMENT ADVISERS ACT OF 1940, AND ENERGY POLICY AND CONSERVATION ACT OF 1975

Rules of General Application
§ 210.4-10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975.

Reserves

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.*, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (*i.e.*, potentially recoverable resources from undiscovered accumulations).

Proved Oil and Gas Reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
- (A) The area identified by drilling and limited by fluid contacts, if any, and
- (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
- (A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
- (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

Reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Probable Reserves

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Possible Reserves

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.
(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

Developed Oil and Gas Reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Undeveloped Oil and Gas Reserves

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

Additional Definitions:

Deterministic Estimate

The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

Probabilistic Estimate

The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Reasonable Certainty

If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

RALPH E. DAVIS
ASSOCIATES, INC.

Certificate of Qualification

I, Allen C. Barron, Registered Professional Engineer, do hereby certify:

1. That I am President of the consulting firm of Ralph E. Davis Associates, Inc. with offices at 1717 St. James Place, Suite 460, Houston, Texas 77056.

2. That I have prepared a reserve report on the interests of the North European Oil Royalty Trust in the Northwest Basin of the Federal Republic of Germany as of October 1, 2013 for the purpose of calculating the cost depletion percentage applicable to Trust unit owners for the 2013 calendar year.

3. That I have no direct or indirect interest, nor do I expect to receive any direct or indirect interest, in the properties or in any securities of the North European Oil Royalty Trust.

4. That I attended The University of Houston and that I graduated with a Bachelor of Science Degree in Chemical Engineering with a Petroleum Engineering Option in 1968.

5. That I am a Registered Professional Engineer in the State of Texas, Registration Number 49284, and that I am a member in good standing of the National Society of Professional Engineers, the Texas Society of Professional Engineers, the Society of Petroleum Engineers, the Society of Petroleum Evaluation Engineers, the American Association of Petroleum geologists and other industry organizations.

6. That I have in excess of forty years of experience in the evaluation of oil and gas properties in the United States, Canada, South America, Asia and Germany, and that I have been practicing as a consultant in petroleum reservoir engineering since 1978.

SIGNED: December 13, 2013

STATE OF TEXAS
ALLEN C. BARRON
49284
LICENSED
PROFESSIONAL ENGINEER

Allen C. Barron, P.E.
President
Ralph E. Davis Associates, Inc.