North European Oil Royalty Trust

Calculation of Cost Depletion Percentage
For 2018 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, 2018

GRAVES & CO. CONSULTING LLC
HOUSTON, TEXAS

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November 29, 2018

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 2018

Trustees:

In accordance with the request of the Trustees of North European Oil Royalty Trust (the "Trust"), the firm of Graves & Co. Consulting LLC of Houston, Texas has performed the calculations necessary to derive the cost depletion percentage for the 2018 calendar year. The cost depletion percentage was prepared for use by unit owners of the Trust in filing federal income tax returns. In order to calculate the cost depletion percentage, we prepared a report of the estimated remaining proved producing reserves attributable to the overriding royalty interests of the Trust in the Northwest German Basin of the Federal Republic of Germany with an effective date of October 1, 2018.

We have reviewed all available information with respect to 100% of the Trust's proved developed properties used 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 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, 2018 and the reported sales are for the twelve-month period ending September 30, 2018. The use of the period ending September 30, 2018 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 prices in effect at the time of the royalty calculations. The price for each of the products is then averaged for the twelve-month period to arrive at the unit price.

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 2018 calendar year. As detailed in Attachment B, the cost depletion percentage for the 2018 calendar year for Trust unit owners is equal to 11.4193% of the unit owner's cost basis as of January 1, 2018.

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 subject to the Trust's royalty interests 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 (1,386,000 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 currently the sole source of royalty income for the Trust. All proved producing reserves within the Oldenburg concession are covered by this report. Although the Trust has royalty interests in other areas, these areas are no longer used in the calculation of the annual cost depletion percentage because there is no current production from these areas.

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 ("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 ("OEG Agreement").

   Under the OEG Agreement, 50% of the field handling and treatment 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 average selling price for sulfur exceeded the indexed base price since the start of fiscal 2013 except for the first quarter of fiscal 2014, all of fiscal 2017 and the first quarter of fiscal 2018. 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 currently comes exclusively 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. The plant's present input capacity stands at approximately 400 million cubic feet ("MMcf") per day following EMPG's retirement of Unit 3 in April, 2017. The elimination of Unit 3 effectively reduces the input capacity by one third.

Total Sales

During the twelve months ending September 30, 2018, total sales for the Oldenburg area were as follows:

	West	East	Total
Gas Well Gas - MMCF	18,911.0	41,793.6	60,704.6
Oil Well Gas - MMCF	35.4	16.5	51.9
Oil & Condensate - Barrels	75,516.0	40,968.8	116,484.8
Sulfur - Short Tons	86,018.9	275,556.7	361,575.6

Gross Reserves

Estimated gross remaining proved producing reserves attributable to the total Oldenburg area as of October 1, 2018 are as follows:

GROSS RESERVES	West	East	Total
Gas Well Gas - MMCF	138,432.9	285,481.8	423,914.7
Oil Well Gas - MMCF	174.4	83.1	257.5
Oil & Condensate - Barrels	1,129,791.5	313,111.6	1,442,903.1
Sulfur - Short Tons	887,140.1	3,586,631.4	4,473,771.5

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%
Mobil Erdgas Sulfur	2%	0%
BEB Gas & Oil	0.6667%(1)	0.6667%(1)
BEB 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, 2018 and net sales for the twelve-month period ending September 30, 2018 are as follows:

	Reserves	Sales
Gas Well Gas - MMCF	8,069.5	1,066.1
Oil Well Gas - MMCF	8.0	1.5
Oil & Condensate - Barrels	53,277.3	3,664.0
Sulfur - Short Tons	44,513.0	3,085.3

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, when available, 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.

Limited information related to actual well production and processing plant operations are provided to the Trust or its representative due to its position as a royalty owner. During early 2018 and continuing at certain intervals during the year, shut-downs occurred which reduced the desulfurization plant throughput. From March 15 to April 15, 2018, throughput was reduced by 40%. From May 18 to June 10, 2018, throughput was reduced by 100%. During the final shutdown period lasting from June 10 to August 21, 2018, the throughput was reduced by 40%. Since sour gas represents approximately two thirds of the total gas produced, these repeated and extended shutdowns had a significant impact on sales.

The reduction in well performance during the above periods and resulting decrease in sulfur production and sales were noted in the review of the overall field performance; however, no reductions in the overall expectations of ultimate recoveries in reserves were taken due to the temporary decreases in throughput.

Limited drilling and recompletion activity were reportedly undertaken during calendar 2018 with minimal success. A sidetracked well was reported to have been successfully tested as a gas well and placed on production in the fall of the year, and another well drilled early in the year is to be placed on production early in 2019. Additional wells are scheduled for drilling in 2019 and 2020.

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 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 10/1/2017 Line (3) is obtained by adding the estimated remaining net proved producing reserves as of 10/1/2017 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 10/1/2017 Line (3). Therefore Line (6) = Line (4) / Line (3).
>
> The product base for each category of proved producing reserves as of 1/1/2017 Line (7) and the adjustment taken during 2017 Line (8) were obtained from the previous year's report. The product base as of 1/1/2018 Line (9) forms the initial starting point for the calculation of the cost depletion percentage for the 2018 tax year. The product base for 1/1/2017 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 1/1/2018 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 1/1/2018 [Sum Line (9)]. Therefore Line (11) = [Sum Line (10)] / [Sum Line (9)].

The cost depletion percentage represents the total allowable cost depletion for the 2018 calendar year for the Trust's unit owners, expressed as a percentage of their cost base as of January 1, 2018.

Neither Graves & Co. Consulting LLC nor any of its directors, officers, employees or contractors 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,

GRAVES & CO. CONSULTING LLC

Allen C. Barron, P.E.
Executive Vice 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, 2018

Oldenburg			
Gas Well Gas MMcf	Oil Well Gas MMcf	Oil/Cond. Barrels	Sulfur Short Tons
8,069	8	53,277	44,513

Five Year Net Sales Summary
12 Months Ending September 30, 2018

	Oldenburg			
	Gas Well Gas MMcf	Oil Well Gas MMcf	Oil/Cond. Barrels	Sulfur Short Tons
2018	1,066	2	3,664	3,085(1)
2017	1,330	2	4,210	4,665(2)
2016	1,392	1	4,225	4,761(3)
2015	1,642	2	4,667	6,090(4)
2014	1,821	1	4,444	7,436(5)

(1) Royalty payments under the Mobil Erdgas sulfur royalty representing second through fourth quarters of fiscal 2018 were received.

(2) No royalty payments under the Mobil Erdgas sulfur royalty representing any of the four quarters of fiscal 2017 were received.

(3) Royalty payments under the Mobil Erdgas sulfur royalty representing all four quarters of fiscal 2016 were received.

(4) Royalty payments under the Mobil Erdgas sulfur royalty representing all four quarters of fiscal 2015 were received.

(5) Royalty payments under the Mobil Erdgas sulfur royalty representing the second through fourth quarters of fiscal 2014 were received.

Attachment B
North European Oil Royalty Trust
Calculation Of Total Cost Depletion Percentage
For the Year Ending December 31, 2018

	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 10-1-2017	9,936	20	43,476
2. Adjustments to reserves during period	-801	-10	13,465
3. Adjusted est. net proved producing reserves as of 10-1-2017	9,135	10	56,941
4. Net sales from 10-1-2017 to 9-30-2018	1,066	2	3,664
5. Estimated remaining net proved producing reserves as of 10-1-2018	8,069	8	53,277
RESERVE DEPLETION FACTOR			
6. Depletion factor	0.11669	0.20000	0.06435
NEORT WEIGHTED PRODUCT BASE ALLOCATION			
7. Product base as of 1-1-2017	2.18542	0.00128	0.10827
8. Less adjustments taken during 2017	0.25800	0.00012	0.00956
9. Product base as of 1-1-2018	1.92742	0.00116	0.09871
10. 2018 Adjustment to product base	0.22492	0.00023	0.00635

11. Cost depletion percentage for 2018 calendar year for Trust unit owners is equal to 11.4193 percent of their 1-1-2018 cost base.

Footnotes:

Line (1) from reserves review as of 10-1-2017
Line (2) from reserves review as of 10-1-2018
Line (3) = Line (1) + Line (2)
Line (4) from BEB and Mobil Erdgas statements
Line (5) from reserves review as of 10-1-2018
Line (6) = Line (4) / Line (3)

Line (7) from 2017 depletion calculations
Line (8) from 2017 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.

Graves & Co. Consulting
Oil and Gas Reserves and Valuations

Certificate of Qualifications

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

1. That I am Executive Vice President of the consulting firm of Graves & Co. Consulting LLC with offices at 2777 Allen Parkway, Suite 1200, Houston, Texas 77019.

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, 2018 for the purpose of calculating the cost depletion percentage applicable to Trust unit owners for the 2018 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 fifty 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: November 29, 2018

GRAVES & CO. CONSULTING LLC

/s/ Allen C. Barron
Allen C. Barron, P.E.
Executive Vice President