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 December 31, 2018

or

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

For the transition period from to

Commission File Number 001-35333

PERMIANVILLE ROYALTY TRUST
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**45-6259461** (I.R.S. Employer Identification No.)
The Bank of New York Mellon Trust Company, N.A., Trustee **601 Travis Street** **16th Floor** **Houston, Texas** (Address of principal executive offices)	**77002** (Zip Code)

Registrant's telephone number, including area code: **1-512-236-6555**

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**

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

None
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o 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 o 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 o

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes o No o

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, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	o	Accelerated filer	x
Non-accelerated filer	o	Smaller reporting company	x
Emerging growth company	o		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.o

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates (24,400,000 Units of Beneficial Interest) computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter was $90,280,000.

As of March 15, 2019, 33,000,000 Units of Beneficial Interest of the Trust were outstanding.

Documents Incorporated By Reference: None

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References to the “Trust” in this document refer to Permianville Royalty Trust, while references to “COERT” or “the Sponsor” in this document refer to COERT Holdings 1, LLC.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes (this “Form 10-K”) “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this Form 10-K, including without limitation the statements under “Trustee’s Discussion and Analysis of Financial Condition and Results of Operations” and “Risk Factors,” regarding the financial position, business strategy, production and reserve growth, and other plans and objectives for the future operations of the Sponsor and regarding future matters relating to the Trust are forward-looking statements. Such statements may be influenced by factors that could cause actual outcomes and results to differ materially from those projected. No assurance can be given that such expectations will prove to have been correct. When used in this document, the words “believes,” “expects,” “anticipates,” “intends” or similar expressions are intended to identify such forward-looking statements. The following important factors, in addition to those discussed elsewhere in this Form 10-K, could affect the future results of the energy industry in general, and the Sponsor and the Trust in particular, and could cause actual results to differ materially from those expressed in such forward-looking statements:

- risks associated with the drilling and operation of oil and natural gas wells;
- the amount of future direct operating expenses and development expenses;
- the effect of existing and future laws and regulatory actions;
- the effect of changes in commodity prices or alternative fuel prices;
- the prohibition on the Trust’s entry into any new hedging arrangements under the terms of the Conveyance;
- conditions in the capital markets;
- competition from others in the energy industry;
- uncertainty of estimates of oil and natural gas reserves and production; and
- cost inflation.

Unitholders should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this Form 10-K. The Trust does not undertake any obligation to release publicly any revisions to the forward-looking statements to reflect events or circumstances after the date of this Form 10-K or to reflect the occurrence of unanticipated events, unless the securities laws require the Trust to do so.

This Form 10-K describes other important factors that could cause actual results to differ materially from expectations of the Sponsor and the Trust, including under the caption “Risk Factors.” All subsequent written and oral forward-looking statements attributable to the Sponsor or the Trust or persons acting on behalf of the Sponsor or the Trust are expressly qualified in their entirety by such factors. The Trust assumes no obligation, and disclaims any duty, to update these forward-looking statements.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

In this Form 10-K the following terms have the meanings specified below.

Bbl—One barrel of 42 U.S. gallons liquid volume, used herein in reference to crude oil and other liquid hydrocarbons.

Boe—One barrel of oil equivalent, computed on an approximate energy equivalent basis that one Bbl of crude oil equals approximately six Mcf of natural gas.

Btu—A British Thermal Unit, a common unit of energy measurement.

Completion—The installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Development Well—A well drilled into a proved oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential—The difference between a benchmark price of oil and natural gas, such as the NYMEX crude oil spot, and the wellhead price received.

Estimated future net revenues—Also referred to as "estimated future net cash flows." The result of applying current prices of oil and natural gas to estimated future production from oil and natural gas proved reserves, reduced by estimated future expenditures, based on current costs to be incurred, in developing and producing the proved reserves, excluding overhead.

Farm-in or farm-out agreement—An agreement under which the owner of a working interest in an oil or natural gas lease typically assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a "farm-in" while the interest transferred by the assignor is a "farm-out."

Field—An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

GAAP—Accounting principles generally accepted in the United States of America.

Gross acres or gross wells—The total acres or wells, as the case may be, in which a working interest is owned.

MBbl—One thousand barrels of crude oil or condensate.

MBoe—One thousand barrels of oil equivalent.

Mcf—One thousand cubic feet of natural gas.

MMBoe—One million barrels of oil equivalent.

MMBtu—One million British Thermal Units.

MMcf—One million cubic feet of natural gas.

Net acres or net wells—The sum of the fractional working interests owned in gross acres or wells, as the case may be.

Net profits interest—A nonoperating interest that creates a share in gross production from an operating or working interest in oil and natural gas properties. The share is measured by net profits from the sale of production after deducting costs associated with that production.

Net revenue interest—An interest in all oil and natural gas produced and saved from, or attributable to, a particular property, net of all royalties, overriding royalties, Net Profits Interests, carried interests, reversionary interests and any other burdens to which the interest is subject.

Plugging and abandonment—Activities to remove production equipment and seal off a well at the end of a well's economic life.

Proved developed reserves—Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved reserves—Under SEC rules, proved reserves are defined as:

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. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) 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. 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. 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. 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 (i) 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 (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. 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.

Proved undeveloped reserves—Proved reserves 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.

PV-10— A non-GAAP financial measure of the present value of estimated future net revenues to be generated from the production of proved reserves, net of estimated future production and development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to income taxes, discounted at 10% per annum.

Recompletion—The completion for production of an existing wellbore in another formation from which that well has been previously completed.

Reservoir—A porous and permeable underground formation containing a natural accumulation of producible oil or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Working interest—The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Workover—Operations on a producing well to restore or increase production.

PART I

Item 1. *Business.*

Permianville Royalty Trust (the “Trust”), previously known as Enduro Royalty Trust, is a Delaware statutory trust formed in May 2011 pursuant to a trust agreement (the “Trust Agreement”) among Enduro Resource Partners LLC (“Enduro”), as trustor, The Bank of New York Mellon Trust Company, N.A. (the “Trustee”), as trustee, and Wilmington Trust Company (the “Delaware Trustee”), as Delaware Trustee.

The Trust was created to acquire and hold for the benefit of the Trust unitholders a net profits interest representing the right to receive 80% of the net profits from the sale of oil and natural gas production from certain properties in the states of Texas, Louisiana and New Mexico held by Enduro as of the date of the conveyance of the net profits interest to the Trust (the “Net Profits Interest”). The properties in which the Trust holds the Net Profits Interest are referred to as the “Underlying Properties.”

In connection with the closing of the initial public offering of units of beneficial interest in the Trust (“Trust Units”) in November 2011, Enduro Operating LLC, a Texas limited liability company and a wholly owned subsidiary of Enduro (“Enduro Operating”), and Enduro Texas LLC, a Texas limited liability company and a wholly owned subsidiary of Enduro (“Enduro Texas”), merged, with each entity surviving the merger. By virtue of the merger, Enduro Texas retained all rights, title and interest to the Net Profits Interest. Enduro Operating and Enduro Texas entered into a Conveyance of Net Profits Interest, dated effective as of July 1, 2011 (as supplemented and amended to date, the “Conveyance”), to effect the transfer of the Net Profits Interest from Enduro Operating to Enduro Texas.

On November 8, 2011, Enduro Texas merged with and into the Trust (the “Trust Merger”) pursuant to an Agreement and Plan of Merger dated November 3, 2011 (the “Trust Merger Agreement”). Under the terms of the Trust Merger Agreement, the Trust continued as the surviving entity, and the limited liability company interest in Enduro Texas held by Enduro prior to the effective time of the Trust Merger converted into the right to receive 33,000,000 Trust Units. Further, by virtue of the Trust Merger, the Trust retained all right, title and interest to the Net Profits Interest (including the right to enforce the Conveyance against Enduro Operating, as grantor). On November 8, 2011, the Trust, Enduro Operating and Enduro Texas entered into a Supplement to Conveyance of Net Profits Interest to acknowledge that The Bank of New York Mellon Trust Company, N.A., as Trustee, is deemed the grantee under the Conveyance and a party thereto.

Immediately following the Trust Merger, Enduro completed an initial public offering of 13,200,000 Trust Units at a price to the public of $22 per unit.

In October 2013, Enduro completed a secondary offering of 11,200,000 Trust Units at a price to the public of $13.85 per unit. The Trust did not sell any Trust Units in the offering and did not receive any proceeds from the offering. After the completion of the secondary offering, Enduro owned 8,600,000 Trust Units, or 26% of the issued and outstanding Trust Units.

At a special meeting of Trust unitholders held on August 30, 2017, unitholders approved several proposals, including amendments to the Trust Agreement and Conveyance. In September 2017, Enduro, the Trustee and the Delaware Trustee entered into the First Amendment to Amended and Restated Trust Agreement, which amended certain provisions of the Trust Agreement to, among other things, allow Enduro to sell interests in the Underlying Properties free and clear of the Net Profits Interest with the approval of Trust unitholders holding at least 50% of the then outstanding units of the Trust at a meeting held in accordance with the requirements of the Trust Agreement. This amendment reduced the required threshold for approval of such sales from 75% to 50% of the outstanding units of the Trust. To effect the same changes as those included in the amended Trust Agreement, Enduro, the Trustee and the Delaware Trustee also entered into the First Amendment to Conveyance of Net Profits Interest. As a result of the Trust unitholders approving amendments to the Trust Agreement and Conveyance and the approval of the divestiture of certain properties in the Permian Basin, Enduro and the Trustee entered into the Partial Release, Reconveyance and Termination Agreement (the “Partial Release”). Pursuant to the terms of the Partial Release, the Trustee, on behalf of the Trust, reconveyed, terminated and released to Enduro the Net Profits Interest with respect to certain of the Underlying Properties sold pursuant to eight letter agreements or purchase and sale agreements, as applicable, entered into between Enduro and eight separate counterparties.

In July 2018, Enduro entered into a purchase and sale agreement with COERT Holdings 1 LLC (“COERT” or the “Sponsor”) for the Underlying Properties and all of the outstanding Trust Units owned by Enduro (the “Sale Transaction”), and on August 31, 2018, the parties closed the Sale Transaction. In connection with the Sale Transaction, COERT assumed all of Enduro’s obligations under the Trust Agreement and other instruments to which Enduro and the Trustee were parties. COERT is a Delaware limited liability company engaged in the production and development of oil and natural gas from properties located in the Rockies, the Permian Basin of west Texas and southeastern New Mexico, and the Arklatex region of Texas and Louisiana.

References to “COERT” or the “Sponsor” in this Form 10-K refer to COERT Holdings 1 LLC, the current sponsor of the Trust, and references to “Enduro” in this Form 10-K refer to Enduro Resource Partners LLC, the original sponsor of the Trust.

The Net Profits Interest is passive in nature and neither the Trust nor the Trustee has any management control over or responsibility for costs relating to the operation of the Underlying Properties. The Net Profits Interest entitles the Trust to receive 80% of the net profits from the sale of oil and natural gas production from the Underlying Properties during the term of the Trust. The Trust Agreement provides that the Trust’s business activities are limited to owning the Net Profits Interest and any activity reasonably related to such ownership, including activities required or permitted by the terms of the Conveyance. As a result, the Trust is not permitted to acquire other oil and natural gas properties or net profits interests or otherwise to engage in activities beyond those necessary for the conservation and protection of the Net Profits Interest.

The Trust has no employees. Administrative functions are performed by the Trustee pursuant to the Trust Agreement. The Trustee has no authority over or responsibility for, and no involvement with, any aspect of the oil and gas operations or other activities on the Underlying Properties. The duties of the Trustee are specified in the Trust Agreement and by the laws of the state of Delaware, except as modified by the Trust Agreement. The Trustee’s principal duties consist of:

- collecting cash attributable to the Net Profits Interest;
- paying expenses, charges and obligations of the Trust from the Trust’s assets;
- distributing distributable cash to the Trust unitholders;

- causing to be prepared and distributed a tax information report for each Trust unitholder and preparing and filing tax returns on behalf of the Trust;

- causing to be prepared and filed reports required to be filed under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), and by the rules of any securities exchange or quotation system on which the Trust Units are listed or admitted to trading;

- causing to be prepared and filed a reserve report by or for the Trust by independent reserve engineers as of December 31 of each year in accordance with criteria established by the Securities and Exchange Commission (the “SEC”);

- establishing, evaluating and maintaining a system of internal control over financial reporting in compliance with the requirements of the Sarbanes-Oxley Act of 2002;

- enforcing the Trust’s rights under certain agreements; and

- taking any action it deems necessary or advisable to best achieve the purposes of the Trust.

In connection with the formation of the Trust, the Trust entered into several agreements with Enduro that imposed obligations upon Enduro, including the Conveyance and a Registration Rights Agreement, which COERT assumed in connection with the Sale Transaction. The Trustee has the power and authority under the Trust Agreement to enforce these agreements on behalf of the Trust. Additionally, the Trustee may from time to time supplement or amend the Conveyance and the Registration Rights Agreement without the approval of Trust unitholders in order to cure any ambiguity, to correct or supplement any defective or inconsistent provisions, to grant any benefit to all of the Trust unitholders, to comply with changes in applicable law or to change the name of the Trust. Such supplement or amendment, however, may not materially adversely affect the interests of the Trust unitholders.

The Trustee may create a cash reserve to pay for future liabilities of the Trust and may authorize the Trust to borrow money to pay administrative or incidental expenses of the Trust that exceed its cash on hand and available reserves. The Trustee may authorize the Trust to borrow from any person, including the Trustee, the Delaware Trustee or an affiliate thereof, although none of the Trustee, the Delaware Trustee nor any affiliate thereof intends to lend funds to the Trust. The Trustee may also cause the Trust to mortgage its assets to secure payment of the indebtedness. The terms of such indebtedness and security interest, if funds were loaned by the Trustee, Delaware Trustee or an affiliate thereof, would be similar to the terms that such entity would grant to a similarly situated commercial customer with whom it did not have a fiduciary relationship. Under the terms of the Trust Agreement, COERT has provided the Trust with a $1.2 million letter of credit to be used by the Trust in the event that its cash on hand (including available cash reserves) is not sufficient to pay ordinary course administrative expenses. If the Trust requires more than the $1.2 million under the letter of credit to pay administrative expenses, COERT has agreed to loan funds to the Trust necessary to pay such expenses. If the Trust borrows funds or draws on the letter of credit, no further distributions will be made to Trust unitholders until such amounts borrowed or drawn are repaid.

Each month, the Trustee pays Trust obligations and expenses and distributes to the Trust unitholders the remaining proceeds received from the Net Profits Interest. The cash held by the Trustee as a reserve against future liabilities or for distribution at the next distribution date may be held in a noninterest-bearing account or may be invested in:

- interest-bearing obligations of the United States government;
- money market funds that invest only in United States government securities;
- repurchase agreements secured by interest-bearing obligations of the United States government; or
- bank certificates of deposit.

The Trust is not subject to any pre-set termination provisions based on a maximum volume of oil or natural gas to be produced or the passage of time. The Trust will dissolve upon the earliest to occur of the following:

- the Trust, upon approval of the holders of at least 75% of the outstanding Trust Units, sells the Net Profits Interest;
- the annual cash proceeds received by the Trust attributable to the Net Profits Interest are less than $2 million for each of any two consecutive years;
- the holders of at least 75% of the outstanding Trust Units vote in favor of dissolution; or
- the Trust is judicially dissolved.

Upon dissolution of the Trust, the Trustee would sell all of the Trust's assets, either by private sale or public auction, and, after payment or the making of reasonable provision for payment of all liabilities of the Trust, distribute the net proceeds of the sale to the Trust unitholders.

Marketing and Post-Production Services

Pursuant to the terms of the Conveyance, the Sponsor has the responsibility to market, or cause to be marketed, the oil and natural gas production attributable to the Net Profits Interest in the Underlying Properties. The terms of the Conveyance restrict the Sponsor from charging any fee for marketing production attributable to the Net Profits Interest other than fees for marketing paid to non-affiliates. Accordingly, a marketing fee is not deducted (other than fees paid to non-affiliates) in the calculation of the Net Profits Interest's share of net profits. The net profits to the Trust from the sales of oil and natural gas production from the Underlying Properties attributable to the Net Profits Interest is determined based on the same price that the Sponsor receives for sales of oil and natural gas production attributable to the Sponsor's interest in the Underlying Properties. However, if the oil or natural gas is processed, the net profits receive the same processing upgrade or downgrade as the Sponsor.

The operators of the Underlying Properties sell the oil produced from the Underlying Properties to third-party crude oil purchasers. Oil production from the Underlying Properties is typically transported by truck from the field to the closest gathering facility or refinery. The operators sell the majority of the oil production from the Underlying Properties under contracts using market sensitive pricing. The price received by the operators for the oil production from the Underlying Properties is usually based on a regional price applied to equal daily quantities in the month of delivery that is then reduced for differentials based upon delivery location and oil quality. Natural gas produced by the operators is marketed and sold to third-party purchasers. The natural gas is sold pursuant to contracts with such third parties, and the sales contracts are in their secondary terms and are on a month-to-month basis. The contract prices are based on a published regional index price, after adjustments for Btu content, transportation and related charges.

The following purchasers individually accounted for ten percent or more of sales from the Underlying Properties that were included in calculating the Trust's "Income from net profits interest" for the periods presented. The table provides the percentage represented by the purchasers during the periods presented:

	Year Ended December 31,		
	2018	**2017**	**2016**
ConocoPhillips	30%	32%	32%
Occidental Petroleum	19%	22%	19%
Navajo Refining	12%	12%	13%

Competition and Markets

The oil and natural gas industry is highly competitive. The Sponsor competes with major oil and natural gas companies and independent oil and natural gas companies for oil and natural gas, equipment, personnel and markets for the sale of oil and natural gas. Many of these competitors are financially stronger than the Sponsor, but even financially troubled competitors can affect the market because of their need to sell oil and natural gas at any price to attempt to maintain cash flow. Because the Sponsor and the third party operators of the Underlying Properties are subject to competitive conditions in the oil and natural gas industry, the Trust's Net Profits Interest is indirectly subject to those same competitive conditions.

Oil and natural gas compete with other forms of energy available to customers, primarily based on price. These alternate forms of energy include electricity, coal and fuel oils. Changes in the availability or price of oil, natural gas or other forms of energy, as well as business conditions, conservation, legislation, regulations and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas.

Future prices for oil and natural gas will directly impact Trust distributions, estimates of reserves attributable to the Trust's interests and estimated and actual future net revenues to the Trust. In view of the many uncertainties that affect the supply and demand for oil and natural gas, neither the Trust nor the Sponsor can make reliable predictions of future oil and natural gas supply and demand or future product prices. Nevertheless, lower product prices generally will result in lower distributions, lower estimates of reserves attributable to the Trust's interests and lower estimated and actual future net revenues to the Trust.

All of the Trust's assets are located in the United States. The operators of the Underlying Properties sell the oil and natural gas produced from the Underlying Properties to third-party purchasers in the United States. Demand for natural gas generally is higher in the winter months, but otherwise seasonal factors do not affect the Trust.

Description of Trust Units

Each Trust Unit is a unit of beneficial interest in the Trust and is entitled to receive cash distributions from the Trust on a pro rata basis. Each Trust unitholder has the same rights regarding his or her Trust Units as every other Trust unitholder has regarding his or her units. The Trust Units are in book-entry form only and are not represented by certificates. The Trust had 33,000,000 Trust Units outstanding as of March 15, 2019.

Distributions and Income Computations

Each month, the Trustee determines the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Net Profits Interest and other sources (such as interest earned on any amounts reserved by the Trustee) that month, over the Trust's liabilities for that month. Available funds are reduced by any cash the Trustee decides to hold as a reserve against future liabilities. The holders of Trust Units as of the applicable record date (generally the last business day of each calendar month) are entitled to monthly distributions payable on or before the 10th business day after the record date. In the event that the net profits for any computation period is a negative amount, the Trust will receive no payment for that period, and any such negative amount plus accrued interest will be deducted from gross profits in the following computation period for purposes of determining the net profits for that following computation period.

Unless otherwise advised by counsel or the Internal Revenue Service ("IRS"), the Trustee will treat the income and expenses of the Trust for each month as belonging to the Trust unitholders of record on the monthly record date. Trust unitholders generally will recognize income and expenses for tax purposes in the month the Trust receives or pays those amounts, rather than in the month the Trust distributes the cash to which such income or expenses (as applicable) relate. Minor variances may occur. For example, the Trustee could establish a reserve in one month that would not result in a tax deduction until a later month.

Transfer of Trust Units

Trust unitholders may transfer their Trust Units in accordance with the Trust Agreement. The Trustee will not require either the transferor or transferee to pay a service charge for any transfer of a Trust Unit. The Trustee may require payment of any tax or other governmental charge imposed for a transfer. The Trustee may treat the owner of any Trust Unit as shown by its records as the owner of the Trust Unit. The Trustee will not be considered to know about any claim or demand on a Trust Unit by any party except the record owner. A person who acquires a Trust Unit after any monthly record date will not be entitled to the distribution relating to that monthly record date. Delaware law and the Trust Agreement govern all matters affecting the title, ownership or transfer of Trust Units.

Periodic Reports

The Trustee files all required Trust federal and state income tax and information returns. The Trustee prepares and mails to Trust unitholders annual reports that Trust unitholders need to correctly report their share of the income and deductions of the Trust. The Trustee also causes to be prepared and filed reports that are required to be filed under the Exchange Act and by the rules of any securities exchange or quotation system on which the Trust Units are listed or admitted to trading, and also causes the Trust to comply with the provisions of the Sarbanes-Oxley Act of 2002, including but not limited to, establishing, evaluating and maintaining a system of internal control over financial reporting in compliance with the requirements of Section 404 thereof.

Each Trust unitholder and his or her representatives may examine, for any proper purpose, during reasonable business hours, the records of the Trust and the Trustee, subject to such restrictions as are set forth in the Trust Agreement.

Liability of Trust Unitholders

Under the Delaware Statutory Trust Act, Trust unitholders are entitled to the same limitation of personal liability extended to stockholders of private corporations for profit under the General Corporation Law of the State of Delaware. The courts in jurisdictions outside of Delaware, however, might not give effect to such limitation.

Voting Rights of Trust Unitholders

The Trustee or Trust unitholders owning at least 10% of the outstanding Trust Units may call meetings of Trust unitholders. The Trust is responsible for all costs associated with calling a meeting of Trust unitholders, unless such meeting is called by the Trust unitholders in which case the Trust unitholders are responsible for all costs associated with calling such meeting. Meetings must be held in such location as is designated by the Trustee in the notice of such meeting. The Trustee must send notice of the time and place of the meeting and the matters to be acted upon to all of the Trust unitholders at least 20 days and not more than 60 days before the meeting. Trust unitholders representing a majority of Trust Units outstanding must be present or represented to have a quorum. Each Trust unitholder is entitled to one vote for each Trust Unit owned. Abstentions and broker non-votes shall not be deemed to be a vote cast.

Unless otherwise required by the Trust Agreement, a matter may be approved or disapproved by the affirmative vote of a majority of the Trust Units present in person or by proxy at a meeting where there is a quorum. This is true even if a majority of the total Trust Units did not approve it. The affirmative vote of the holders of at least 75% of the outstanding Trust Units is required to:

- dissolve the Trust;
- amend the Trust Agreement (except with respect to certain matters that do not adversely affect the rights of Trust unitholders in any material respect); or
- approve the sale of all the assets of the Trust (including the sale of the Net Profits Interest).

At the special meeting of Trust unitholders held on August 30, 2017, unitholders approved amendments to the Trust Agreement. In September 2017, Enduro, the Trustee and the Delaware Trustee entered into the First Amendment to Amended and Restated Trust Agreement, which amended certain provisions of the Trust Agreement to, among other things, allow Enduro (and, therefore, following the Sale Transaction, the Sponsor) to sell interests in the Underlying Properties free and clear of the Net Profits Interest with the approval of Trust unitholders holding at least 50% of the then outstanding units of the Trust at a meeting held in accordance with the requirements of the Trust Agreement. This amendment reduced the required threshold for approval of such sales from 75% to 50% of the outstanding units of the Trust.

In addition, certain amendments to the Trust Agreement may be made by the Trustee without approval of the Trust unitholders.

Computation of Net Profits

The provisions of the Conveyance governing the computation of the net profits are detailed and extensive. The following information summarizes the material provisions of the Conveyance related to the computation of the net profits, but is qualified in its entirety by the text of the Conveyance, which is incorporated by reference as an exhibit to this Annual Report on Form 10-K.

Net Profits Interest

The amounts paid to the Trust for the Net Profits Interest are based on, among other things, the definitions of "gross profits" and "net profits" contained in the Conveyance and described below. Under the Conveyance, net profits are computed monthly, and 80% of the aggregate net profits attributable to the sale of oil and natural gas production from the Underlying Properties for each calendar month will be paid to the Trust on or before the end of the following month. The Sponsor will not pay to the Trust any interest on the net profits held by the Sponsor prior to payment to the Trust, provided that such payments are timely made.

"*Gross profits*" means the aggregate amount received by the Sponsor from and after July 1, 2011 from sales of oil and natural gas produced from the Underlying Properties that are not attributable to a production month that occurs prior to June 1, 2011 (after deducting the appropriate share of all royalties and any overriding royalties, production payments and other similar charges (in each case, in existence as of June 1, 2011) and other than certain excluded proceeds, as described in the Conveyance), including all proceeds and consideration received (i) directly or indirectly, for advance payments, (ii) directly or indirectly, under take-or-pay and similar provisions of production sales contracts (when credited against the price for delivery of production) and (iii) under balancing arrangements. Gross profits do not include consideration for the transfer or sale of any Underlying Property by the Sponsor or any subsequent owner to any new owner, unless the Net Profits Interest is released (as is permitted under certain circumstances). Gross profits also do not include any amount for oil or natural gas lost in production or marketing or used by the owner of the Underlying Properties in drilling, production and plant operations.

"*Net profits*" means, as more fully set forth in the Conveyance, gross profits less the following costs, expenses and, where applicable, losses, liabilities and damages all as actually incurred by the Sponsor and attributable to the Underlying Properties on or after July 1, 2011 but that are not attributable to a production month that occurs prior to July 1, 2011 (as such items are reduced by any offset amounts, as described in the Conveyance):

- with the exception of certain costs and expenses related to 20 wells located in the Haynesville Shale identified in the Conveyance, all costs for (i) drilling, development, production and abandonment operations, (ii) all direct labor and other services necessary for drilling, operating, producing and maintaining the Underlying Properties and workovers of any wells located on the Underlying Properties, (iii) treatment, dehydration, compression, separation and transportation, (iv) all materials purchased for use on, or in connection with, any of the Underlying Properties and (v) any other operations with respect to the exploration, development or operation of hydrocarbons from the Underlying Properties;

- all losses, costs, expenses, liabilities and damages with respect to the operation or maintenance of the Underlying Properties for (i) defending, prosecuting, handling, investigating or settling litigation, administrative proceedings, claims, damages, judgments, fines, penalties and other liabilities, (ii) the payment of certain judgments, penalties and other liabilities, (iii) the payment or restitution of any proceeds of hydrocarbons from the Underlying Properties, (iv) complying with applicable local, state and federal statutes, ordinance, rules and regulations, (v) tax or royalty audits and (vi) any other loss, cost, expense, liability or damage with respect to the Underlying Properties not paid or reimbursed under insurance;

- all taxes, charges and assessments (excluding federal and state income, transfer, mortgage, inheritance, estate, franchise and like taxes) with respect to the ownership of, or production of hydrocarbons from, the Underlying Properties;

- all insurance premiums attributable to the ownership or operation of the Underlying Properties for insurance actually carried with respect to the Underlying Properties, or any equipment located on any of the Underlying Properties, or incident to the operation or maintenance of the Underlying Properties;

- all amounts and other consideration for (i) rent and the use of or damage to the surface, (ii) delay rentals, shut-in well payments and similar payments and (iii) fees for renewal, extension, modification, amendment, replacement or supplementation of the leases included in the Underlying Properties;

- all amounts charged by the relevant operator as overhead, administrative or indirect charges specified in the applicable operating agreements or other arrangements covering the Underlying Properties or the Sponsor's operations with respect thereto;

- to the extent that the Sponsor is the operator of certain of the Underlying Properties and there is no operating agreement covering such portion of the Underlying Properties, those overhead, administrative or indirect charges that are allocated by the Sponsor to such portion of the Underlying Properties;

- if, as a result of the occurrence of the bankruptcy or insolvency or similar occurrence of any purchaser of hydrocarbons produced from the Underlying Properties, any amounts previously credited to the determination of the net profits are reclaimed from the Sponsor, then the amounts reclaimed;

- all costs and expenses for recording the Conveyance and, at the applicable times, terminations and/or releases thereof;

- amounts previously included in gross profits but subsequently paid as a refund, interest or penalty; and

- at the option of the Sponsor (or any subsequent owner of the Underlying Properties), amounts reserved for approved development expenditure projects, including well drilling, recompletion and workover costs, which amounts will at no time exceed $2.0 million in the aggregate, and will be subject to the limitations described below (provided that such costs shall not be debited from gross profits when actually incurred).

As mentioned above, the costs deducted in the net profits determination will be reduced by certain offset amounts. The offset amounts are further described in the Conveyance, and include, among other things, certain net proceeds attributable to the treatment or processing of hydrocarbons produced from the Underlying Properties and certain non-production revenues, including salvage value for equipment related to plugged and abandoned wells. If the offset amounts exceed the costs during a monthly period, the ability to use such excess amounts to offset costs will be deferred and utilized as offsets in the next monthly period to the extent such amounts, plus accrued interest thereon, together with other offsets to costs, for the applicable month, are less than the costs arising in such month.

The Trust is not liable to the owners of the Underlying Properties or the operators for any operating capital or other costs or liabilities attributable to the Underlying Properties. The Trustee expects to make distributions to Trust unitholders monthly; however, in the event that the net profits for any computation period is a negative amount, the Trust will receive no payment for that period, and any such negative amount plus accrued interest will be deducted from gross profits in the following computation period for purposes of determining the net profits for that following computation period.

The Trust uses the modified cash basis of accounting to report Trust receipts of the Net Profits Interest and payments of expenses incurred. The Net Profits Interest represents the right to receive revenues (oil and natural gas sales), less direct operating expenses (lease operating expenses and production and property taxes) and development expenses of the Underlying Properties, multiplied by 80%. Cash distributions of the Trust will be made based on the amount of cash received by the Trust pursuant to terms of the Conveyance.

Additional Provisions

If a controversy arises as to the sales price of any production, then for purposes of determining gross profits:

- any proceeds that are withheld for any reason (other than at the request of the Sponsor) are not considered received until such time that the proceeds are actually collected;
- amounts received and promptly deposited with a non-affiliated escrow agent will not be considered to have been received until disbursed to the Sponsor by the escrow agent; and
- amounts received and not deposited with an escrow agent will be considered to have been received.

The Trustee is not obligated to return any cash received from the Net Profits Interest. Any overpayments made to the Trust by the Sponsor due to adjustments to prior calculations of net profits or otherwise will reduce future amounts payable to the Trust until the Sponsor recovers the overpayments plus interest at a prime rate (as described in the Conveyance).

The Conveyance generally permits the Sponsor to transfer without the consent or approval of the Trust unitholders all or any part of its interest in the Underlying Properties, subject to the Net Profits Interest. The Trust unitholders are not entitled to any proceeds of a sale or transfer of the Sponsor's interest. Except in certain cases where the Net Profits Interest is released, following a sale or transfer, the Underlying Properties will continue to be subject to the Net Profits Interest, and the gross profits attributable to the transferred property will be calculated, paid and distributed by the transferee to the Trust. The Sponsor will have no further obligations, requirements or responsibilities with respect to any such transferred interests.

In addition, the Sponsor may, without the consent of the Trust unitholders, require the Trustee to release the Net Profits Interest associated with any lease that accounts for less than or equal to 0.25% of the total production from the Underlying Properties in the prior 12 months, provided that the Net Profits Interest covered by such releases cannot exceed, during any 12-month period, an aggregate fair market value to the Trust of $500,000. These releases will be made only in connection with a sale by the Sponsor to a non-affiliate of the relevant Underlying Properties and are conditioned upon an amount equal to the fair value to the Trust of such Net Profits Interest being treated as an offset amount against costs and expenses. In January 2019, the Sponsor sold two producing wells and associated acreage of the Underlying Properties under this provision for a sale price of approximately $62,000, and the Trustee released such properties from the Net Profits Interest

As the designated operator of a property included in the Underlying Properties, the Sponsor may enter into farm-out, operating, participation and other similar agreements to develop the property, but any transfers made in connection with such agreements will be made subject to the Net Profits Interest. The Sponsor may enter into any of these agreements without the consent or approval of the Trustee or any Trust unitholder.

The Sponsor has the right to release, surrender or abandon its interest in any Underlying Property that will no longer produce (or be capable of producing) hydrocarbons in paying quantities (determined without regard to the Net Profits Interest). Upon such release, surrender or abandonment, the portion of the Net Profits Interest relating to the affected property will also be released, surrendered or abandoned, as applicable. The Sponsor also has the right to abandon an interest in the Underlying Properties if (a) such abandonment is necessary for health, safety or environmental reasons or (b) the hydrocarbons that would have been produced from the abandoned portion of the Underlying Properties would reasonably be expected to be produced from wells located on the remaining portion of the Underlying Properties.

The Sponsor must maintain books and records sufficient to determine the amounts payable for the Net Profits Interest to the Trust. Monthly and annually, the Sponsor must deliver to the Trustee a statement of the computation of the net profits for each computation period. The Trustee has the right to inspect and review the books and records maintained by the Sponsor during normal business hours and upon reasonable notice. The Sponsor has further agreed to provide the Trust and Trustee with all information and services as are reasonably necessary to fulfill the purposes of the Trust, including such accounting, bookkeeping and informational services as may be necessary for the preparation of reports the Trust is required to prepare or file in accordance with applicable tax and securities laws, exchange listing rules and other requirements, including reserve reports and tax returns. Following the sale of all or any portion of the Underlying Properties, the purchaser will be bound by the obligations of the Sponsor under the Trust Agreement and the Conveyance with respect to the portion sold.

U.S. Federal Income Tax Matters

The following is a summary of certain U.S. federal income tax matters that may be relevant to the Trust unitholders. This summary is based upon current provisions of the Internal Revenue Code of 1986, as amended (the "Code"), existing and proposed Treasury regulations thereunder and current administrative rulings and court decisions, all of which are subject to changes that may or may not be retroactively applied. No attempt has been made in the following summary to comment on all U.S. federal income tax matters affecting the Trust or the Trust unitholders.

The summary has limited application to non-U.S. persons and persons subject to special tax treatment such as, without limitation: banks, insurance companies or other financial institutions; Trust unitholders subject to the alternative minimum tax; tax-exempt organizations; dealers in securities or commodities; regulated investment companies; real estate investment trusts; traders in securities that elect to use a mark-to-market method of accounting for their securities holdings; non-U.S. Trust unitholders that are "controlled foreign corporations" or "passive foreign investment companies"; persons that are S-corporations, partnerships or other pass-through entities; persons that own their interest in the Trust Units through S-corporations, partnerships or other pass-through entities; persons that at any time own more than 5% of the aggregate fair market value of the Trust Units; expatriates and certain former citizens or long-term residents of the United States; U.S. Trust unitholders whose functional currency is not the U.S. dollar; persons who hold the Trust Units as a position in a hedging transaction, "straddle", "conversion transaction" or other risk reduction transaction; or persons deemed to sell the Trust Units under the constructive sale provisions of the Code. Each Trust unitholder should consult his or her own tax advisor with respect to his or her particular circumstances.

Classification and Taxation of the Trust

Tax counsel to the Trust advised the Trust at the time of formation that, for U.S. federal income tax purposes, in its opinion, the Trust would be treated as a grantor trust and not as an unincorporated business entity. No ruling has been or will be requested from the IRS or another taxing authority. The remainder of the discussion below is based on tax counsel's opinion, at the time of formation, that the Trust will be classified as a grantor trust for U.S. federal income tax purposes. As a grantor trust, the Trust is not subject to U.S. federal income tax at the trust level. Rather, each Trust unitholder is considered for U.S. federal income tax purposes to own its proportionate share of the Trust's assets directly as though no Trust were in existence. The income of the Trust is deemed to be received or accrued by the Trust unitholder at the time such income is received or accrued by the Trust, rather than when distributed by the Trust. Each Trust unitholder is subject to tax on its proportionate share of the income and gain attributable to the assets of the Trust and is entitled to claim its proportionate share of the deductions and expenses attributable to the assets of the Trust, subject to applicable limitations, in accordance with the Trust unitholder's tax method of accounting and taxable year without regard to the taxable year or accounting method employed by the Trust.

The Trust files annual information returns, reporting to the Trust unitholders all items of income, gain, loss, deduction and credit. The Trust allocates these items of income, gain, loss, deduction and credit to Trust unitholders based on record ownership on the monthly record dates. It is possible that the IRS or another taxing authority could disagree with this allocation method and assert that income and deductions of the Trust should be determined and allocated on a daily or prorated basis, which could require adjustments to the tax returns of the unitholders affected by this issue and result in an increase in the administrative expense of the Trust in subsequent periods.

Under current law, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 37%, and the highest marginal U.S. federal income tax rate applicable to long-term capital gains (generally, gains from the sale or exchange of certain investment assets held for more than one year) and qualified dividends of individuals is generally 20%. Such marginal tax rates may be effectively increased due to the phaseout of personal exemptions and certain limitations and prohibitions on itemized deductions. The highest marginal U.S. federal income tax rate applicable to corporations is 21%, and such rate applies to both ordinary income and capital gains.

Section 1411 of the Code imposes a 3.8% Medicare tax on certain investment income earned by individuals, estates, and trusts (and a reduced 1.4% tax on certain tax-exempt organizations). For these purposes, investment income generally will include a unitholder's allocable share of the trust's interest and royalty income plus the gain recognized from a sale of Trust units. In the case of an individual, the tax is imposed on the lesser of (i) the individual's net investment income from all investments, or (ii) the amount by which the individual's modified adjusted gross income exceeds specified threshold levels depending on such individual's U.S. federal income tax filing status. In the case of an estate or trust, the tax is imposed on the lesser of (i) undistributed net investment income, or (ii) the excess adjusted gross income over the dollar amount at which the highest income tax bracket applicable to an estate or trust begins.

If a taxpayer disposes of any "Section 1254 property" (certain oil, gas, geothermal or other mineral property), and the adjusted basis of such property includes adjustments for depletion deductions under Section 611 of the Code, the taxpayer generally must recapture the amount deducted for depletion as ordinary income (to the extent of gain realized on the disposition of the property). This depletion recapture rule applies to any disposition of property that was placed in service by the taxpayer after December 31, 1986. Detailed rules set forth in Sections 1.1254-1 through 1.1254-6 of the U.S. Treasury Regulations govern dispositions of property after March 13, 1995. The IRS likely will take the position that a unitholder must recapture depletion upon the disposition of a unit.

Classification of the Net Profits Interest

Tax counsel to the Trust advised the Trust at the time of formation that, for U.S. federal income tax purposes, based upon the reserve report and representations made by the Trust regarding the expected economic life of the Underlying Properties and the expected duration of the Net Profits Interest, in its opinion the Net Profits Interest attributable to proved developed reserves will and the Net Profits Interest attributable to proved undeveloped reserves should be treated as continuing, nonoperating economic interests in the nature of royalties payable out of production from the mineral interests they burden. No assurance can be given that the IRS or another taxing authority will not assert that the Net Profits Interest should be treated differently. Any such different treatment could affect the amount, timing and character of income, gain or loss in respect of an investment in Trust Units.

Reporting Requirements for Widely-Held Fixed Investment Trusts

The Trustee assumes that some Trust Units are held by middlemen, as such term is broadly defined in the Treasury regulations (and includes custodians, nominees, certain joint owners and brokers holding an interest for a custodian street name, collectively referred to herein as "middlemen"). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. The Bank of New York Mellon Trust Company, N.A., 601 Travis Street, Houston, Texas 77002, telephone number 1-512-236-6545, is the representative of the Trust that will provide the tax information in accordance with applicable Treasury regulations governing the information reporting requirements of the Trust as a WHFIT. Notwithstanding the foregoing, the middlemen holding Trust Units on behalf of unitholders, and not the Trustee of the Trust, are solely responsible for complying with the information reporting requirements under the Treasury regulations with respect to such Trust Units, including the issuance of IRS Forms

1099 and certain written tax statements. Unitholders whose Trust Units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the Trust Units. Any generic tax information provided by the Trustee of the Trust is intended to be used only to assist Trust unitholders in the preparation of their federal and state income tax returns.

Available Trust Tax Information

In compliance with the Treasury regulations reporting requirements for WHFITs and the dissemination of Trust tax reporting information, the Trustee provides a generic tax information reporting booklet which is intended to be used only to assist Trust unitholders in the preparation of their federal and state income tax returns. This tax information booklet can be obtained at www.permianvilleroyaltytrust.com.

Environmental Matters and Regulation

General. For purposes of the discussion in this section, the oil and natural gas production operations conducted on the properties that are subject to the Net Profits

Interest are referred to as the "Sponsor's operations." The Sponsor's oil and natural gas exploration and production operations are subject to stringent and comprehensive federal, regional, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose significant obligations on the Sponsor's operations, including requirements to:

- obtain permits to conduct regulated activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- restrict the types, quantities and concentration of materials that can be released into the environment in the performance of drilling, completion and production activities;
- initiate investigatory and remedial measures to mitigate pollution from former or current operations, such as restoration of drilling pits and plugging of abandoned wells; and
- apply specific health and safety criteria addressing worker protection.

Failure to comply with environmental laws and regulations may result in the assessment of significant administrative, civil and criminal sanctions, including monetary penalties, the imposition of joint and several liability, investigatory and remedial obligations, and the issuance of injunctions limiting or prohibiting some or all of the Sponsor's operations. Moreover, these laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. The Sponsor has advised the Trustee that it believes that it is in substantial compliance with all existing environmental laws and regulations applicable to its current operations and that its continued compliance with existing requirements will not have a material adverse effect on the cash distributions to the Trust unitholders. While the Trump Administration has taken steps aimed at reducing federal regulatory burdens and costs for oil and natural gas production operations, the recent trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly construction, drilling, water management, completion, emission or discharge limits or waste handling, disposal or remediation obligations could have a material adverse effect on the Sponsor's development expenses, results of operations and financial position. The Sponsor may be unable to pass on those increases to its customers. Moreover, accidental releases or spills may occur in the course of the Sponsor's operations, and there can be no assurance that the Sponsor will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons.

The following is a summary of certain existing environmental, health and safety laws and regulations to which the Sponsor's business operations are subject.

Hazardous substance and wastes. The Comprehensive Environmental Response, Compensation and Liability Act, or "CERCLA," also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. Under CERCLA, these "responsible persons" may include the owner or operator of the site where the release occurred, and entities that transport, dispose of or arrange for the transport or disposal of hazardous substances released at the site. These responsible persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency ("EPA") and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third-parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Sponsor generates materials in the course of its operations that may be regulated as hazardous substances.

The Resource Conservation and Recovery Act, or "RCRA," and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, production and development of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes ("E&P Wastes") now classified as non-hazardous could be classified as hazardous wastes in the future. In accordance with a December 2016 settlement agreement, the EPA agreed to decide by March 2019 whether to revise the EPA's current determination exempting oil and gas wastes from regulation as hazardous waste under RCRA. While the EPA has not taken any action toward changing the status of oil and gas wastes under RCRA, any such change could result in an increase in the costs to manage and dispose of wastes, which could have a material adverse effect on the cash distributions to the Trust unitholders. In addition, the Sponsor generates industrial wastes in the ordinary course of its operations that may be regulated as hazardous wastes. Such wastes must be properly tested, characterized and disposed of according to state and federal regulations.

The properties upon which the Sponsor conducts its operations have been used for oil and natural gas exploration and production for many years. Although the Sponsor and, as applicable, the Sponsor's predecessor, Enduro, may have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons and wastes may have been disposed of or released at or from the real properties upon which the Sponsor conducts its operations, or at or from other, offsite locations, where these petroleum hydrocarbons and wastes have been taken for recycling or disposal. In addition, the properties upon which the Sponsor conducts its operations may have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons was not under the Sponsor's control. These properties and the petroleum hydrocarbons and wastes disposed or released at or from these properties may be subject to CERCLA, RCRA and analogous state laws. Under such laws, the Sponsor could be required to remove or remediate previously disposed wastes, to clean up contaminated property and to perform remedial operations such as restoration of pits and plugging of abandoned wells to prevent future contamination or to pay some or all of the costs of any such action.

Water discharges. The Clean Water Act ("CWA") and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil, into federal and state waters. The discharge of pollutants into "waters of the United States" is prohibited, except in accordance with the terms of a permit issued by EPA and/or an analogous state agency. The term "waters of the United States" has been broadly defined to include certain inland water bodies, including certain wetlands and intermittent streams. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers ("ACE"). CWA Section 401 provides that the applicant for an individual National Pollutant Discharge Elimination System ("NPDES") permit to be issued by the EPA or an individual Section 404 permit to be issued by the ACE must notify the state in which the discharge will occur and provide an opportunity for the state to determine if the discharge will comply with the state’s approved water quality program. In some instances this process could result in delay in issuance of the permit, more stringent permit requirements, or denial of the permit.

In September 2015, new EPA and ACE rules defining the scope of the “waters of the United States,” and the EPA’s and the ACE’s jurisdiction, became effective (“2015 Rule”). The 2015 Rule has been challenged in multiple courts on the grounds that it unlawfully expands the reach of CWA programs. Due to the status of pending litigation, the 2015 Rule is currently in effect in 22 states. In the remaining states, regulations in effect before promulgation of the 2015 Rule and guidance interpreting relevant United States Supreme Court rulings are in effect. On December 11, 2018, the heads of the EPA and ACE signed a proposed regulation that would revise the definition of waters of the United States to reduce its reach from the 2015 Rule (“2018 Pre-Proposal Rule”). The fates of the 2015 Rule and the 2018 Pre-Proposal Rule and applicability of the rules during current and future litigation are uncertain; however, to the extent the 2015 Rule is in effect, it expands the scope of CWA jurisdiction, and COERT could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas or other waters of the United States.

Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. Spill prevention, control and countermeasure (“SPCC”) plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of waters of the United States in the event of a hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws required individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. In June 2016, the EPA issued a final rule implementing wastewater pretreatment standards that prohibit onshore unconventional oil and gas extraction facilities from sending wastewater directly to publicly owned treatment works ("POTWs"). Unconventional oil and gas extraction facilities can send wastewater to a private wastewater treatment facility that can either discharge treated wastewater or send it to a POTW. The EPA is conducting a related study of treatment of oil and gas extraction wastewater at private wastewater treatment facilities. This restriction of disposal options for hydraulic fracturing waste and other changes to CWA requirements may result in increased costs to the Sponsor. In addition, naturally occurring radioactive material ("NORM") is brought to the surface in connection with oil and gas production. Concerns have arisen over traditional NORM disposal practices (including discharge through publicly owned treatment works into surface waters), which may increase the costs associated with management of NORM.

The Oil Pollution Act of 1990, as amended, or OPA, amends the CWA and establishes strict liability and natural resource damages liability for unauthorized discharges of oil into waters of the United States. OPA requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Hydraulic fracturing. Various federal and state initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formation to stimulate production of oil and natural gas. The U.S. Congress has considered legislation to amend the federal Safe Drinking Water Act ("SDWA") to subject hydraulic fracturing operations to regulation under the SDWA's Underground Injection Control Program and to require the disclosure of chemicals used in the hydraulic fracturing process. Any such legislation could make it easier for third parties opposed to hydraulic fracturing to initiate legal proceedings against companies. In addition, the federal government is currently undertaking several studies of hydraulic fracturing's potential impacts. The Secretary of Energy Advisory Board published their ninety-day report that included a number of recommendations. In December 2016, the EPA issued a final report on the potential impacts of hydraulic fracturing on drinking water resources. The report did not find widespread, systematic impacts to drinking water from hydraulic fracturing; at the same time, the report acknowledged information gaps that limited EPA's ability to fully assess the potential impacts to drinking water resources. In addition, as noted above, the EPA in June 2016 issued a final rule implementing wastewater pretreatment standards that prohibit onshore unconventional oil and gas extraction facilities from sending wastewater directly to POTWs. EPA is conducting a related study of oil and gas extraction wastewater at private wastewater treatment facilities. In March 2015, the federal Bureau of Land Management ("BLM") released a final rule establishing new or more stringent standards for performing hydraulic fracturing operations on federal and tribal lands. Several states, trade groups and companies have challenged the legality of the BLM rule in federal court. On September 30, 2015, the U.S. District Court for the District of Wyoming issued a preliminary injunction, blocking BLM from enforcing the new rules nationwide, and on June 21, 2016, the court issued a final ruling striking down the BLM rule. While the U.S. Department of Interior initially has appealed the decision to the Tenth Circuit Court of Appeals. BLM announced in March 2017 that it intended to rescind the rule. On December 29, 2017, BLM published a final rule that rescinded the 2015 hydraulic fracturing rule.

On August 16, 2012 the EPA published final rules that extend New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPs") to certain exploration and production operations. The final rule requires the use of reduced emission completions or "green completions" on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. In response to some of these challenges, the EPA amended the rule to extend compliance dates for certain storage vessels, and may issue additional revised rules in response to additional such requests in the future. Only a portion of these new rules appear to affect our operations at this time by requiring new air emissions controls, equipment modification, maintenance, monitoring, recordkeeping and reporting. Although these new requirements will increase our operating and capital expenditures and it is possible that the EPA will adopt further regulation that could further increase our operating and capital expenditures, we do not currently expect such existing and new regulations will have a material adverse impact on our operations or financial results.

Some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances, including the disclosure of information regarding the substances used in the hydraulic fracturing process. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is regulated at the federal level, the Sponsor's and the third party operators' fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. In December 2014, the Governor of New York announced that the state would maintain its moratorium on hydraulic fracturing in the state. Further, some local governments, including in Texas, have imposed moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities. No assurance can be given as to whether or not similar measures might be considered or implemented in the jurisdictions in which the Underlying Properties are located.

Air emissions. The federal Clean Air Act ("CAA") and comparable state laws restrict the emission of air pollutants from many sources through air emissions permitting and regulatory programs and also impose various monitoring and reporting requirements. These laws and regulations may require the Sponsor to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air emissions permit requirements or incur development expenses to install and utilize specific equipment or technologies to control emissions. For example, the EPA in 2012 adopted federal New Source Performance Standards ("NSPS") that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. In June 2016, the EPA published a final rule adopting additional NSPS requirements for new, modified, or reconstructed oil and gas facilities that require control of the greenhouse gas methane from affected facilities, including requirements to find and repair fugitive leaks of methane emissions at well sites ("Methane Rule"). Following the 2016 presidential election and change in administrations, in 2017 the EPA proposed to delay implementation of the Methane Rule and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been, or are likely to be, challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require the Sponsor to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from its operations, which could reduce the profits available to the Trust and potentially impair the economic development of the Underlying Properties. Obtaining permits has the potential to delay the development of oil and natural gas projects. Federal and state regulatory agencies may impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal CAA and associated state laws and regulations.

Climate change. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" or "GHGs," and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to the scientific studies, international negotiations to address climate change have occurred. In December 2015, the United States participated in the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement (adopted at the conference) calls for nations to undertake efforts with respect to global temperatures and GHG emissions. If ratified, the Paris Agreement will take effect in 2020. The United States ratified the Paris Agreement in September 2016; however, the country's future participation in the Paris Agreement is uncertain. In June 2017, President Trump announced that the United States would withdraw from the Paris Agreement, but that it may enter into a future international agreement related to GHGs. In August 2017, the State Department officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement. Such withdrawal has not yet been finalized, and whether the United States may reenter the Paris Agreement or a separately negotiated agreement is unclear at this time. Further, several states and local governments remain committed to the principles of the Paris Agreement in their effectuation of policy and regulations. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the Paris Agreement.

Both houses of Congress have actively considered legislation to reduce emissions of GHGs, and many states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. Although it is not possible at this time to predict when Congress may pass climate change legislation, any future federal or state laws that may be adopted to address GHG emissions could require the Sponsor to incur increased operating costs and could adversely affect demand for the oil and natural gas the Sponsor produces.

The EPA has also taken regulatory action aimed at reducing GHG emissions. In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment, which has allowed the EPA to adopt and implement regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act. For example, the EPA adopted regulations under Prevention of Significant Deterioration ("PSD") and Title V permitting programs for GHG emissions from certain large stationary sources. In June 2014, the U.S. Supreme Court held that GHG emissions alone cannot trigger an obligation to obtain a federal air permit, but the Court upheld EPA's authority to regulate GHG emissions from major stationary sources where emissions of traditional criteria pollutants exceed federal permitting thresholds. In November 2010, the EPA published its final rule expanding the existing GHG monitoring and reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. These requirements became applicable in 2012 for emissions occurring in 2011. The Underlying Properties may be subject to these requirements or become subject to them in the future. Meanwhile, as noted above, in June 2016 the EPA finalized the Methane Rule. Following the 2016 presidential election and change in administrations, however, in 2017 the EPA proposed to delay implementation of the Methane Rule, and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been (or are likely to be) challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require the Sponsor to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from its operations. In addition, in November 2016, the U.S. Department of the Interior Bureau of Land Management ("BLM") issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on federal and tribal lands that are substantially similar to the EPA's Methane Rule. However, in December 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 17, 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule revising or rescinding certain provisions of the 2016 rule. Although the future implementation of the EPA and BLM rules aimed at controlling GHG emissions from oil and natural gas sources remains uncertain, future federal GHG regulations for the oil and gas industry remain a possibility given the long-term trend towards increasing regulation.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact the Sponsor's operations. In addition to these regulatory developments, recent judicial decisions that have allowed certain tort claims alleging property damage to proceed against GHG emissions sources may increase the Sponsor's litigation risk for such claims. The adoption of any future regulations that require reporting of GHGs or otherwise limit emissions of GHGs from the equipment and operations of the Sponsor could require the Sponsor to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with its operations, and such requirements also could adversely affect demand for the oil and natural gas that the Sponsor produces.

Legislation or regulations that may be adopted to address climate change could also affect the markets for the Sponsor's products by making its products more or less desirable than competing sources of energy. To the extent that its products are competing with higher greenhouse gas emitting energy sources, the Sponsor's products would become more desirable in the market with more stringent limitations on greenhouse gas emissions. In August 2015, the EPA issued standards designed to limit GHG emissions from new power plants as well as the Clean Power Plan aimed at reducing GHG emissions from existing power plants. In February 2016, the U.S. Supreme Court stayed the implementation of the Clean Power Plan pending judicial review, and President Trump has been vocal in opposition to the Clean Power Plan. In October 2017, following a review directed by President Trump's Energy Independence Executive Order, the EPA proposed to repeal the Clean Power Plan regulations. To the extent that its products are competing with lower greenhouse gas emitting energy, the Sponsor's products would become less desirable in the market with more stringent limitations on greenhouse gas emissions. The Sponsor cannot predict with any certainty at this time how these possibilities may affect its operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas produced by the Sponsor or otherwise cause the Sponsor to incur significant costs in preparing for or responding to those effects.

National Environmental Policy Act. Oil and natural gas exploration, development and production activities on federal lands are subject to the National Environmental Policy Act, as amended ("NEPA"). NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. However, for those current activities as well as for future or proposed exploration and development plans on federal lands, governmental permits or authorizations that are subject to the requirements of NEPA are required. This process has the potential to delay the development of oil and natural gas projects.

Endangered Species Act. The federal Endangered Species Act and similar state statutes restrict activities that may affect endangered and threatened species or their habitats. The presence of endangered species or designation of previously unidentified endangered or threatened species could cause the Sponsor to incur additional costs or become subject to operating delays, restrictions or bans in the affected areas.

Employee health and safety. The operations of the Sponsor are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act ("OSHA") and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens.

Where You Can Find Other Information

We maintain a website at http://www.permianvilleroyaltytrust.com. The Trust's filings under the Exchange Act are available at our website and are also available electronically from the website maintained by the SEC at http://www.sec.gov. In addition, the Trust will provide electronic copies of its recent filings free of charge to the Trust unitholders upon request to the Trustee.

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

Prices of oil and natural gas fluctuate, and lower prices could reduce proceeds to the Trust and cash distributions to unitholders.

The Trust's reserves and monthly cash distributions are highly dependent upon the prices realized from the sale of oil and natural gas. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and the Sponsor. These factors include, among others:

- regional, domestic and foreign supply and perceptions of supply of oil and natural gas;
- the level of demand and perceptions of demand for oil and natural gas;
- political conditions or hostilities in oil and natural gas producing regions;
- anticipated future prices of oil and natural gas and other commodities;
- weather conditions and seasonal trends;
- technological advances affecting energy consumption and energy supply;
- U.S. and worldwide economic conditions;
- the price and availability of alternative fuels;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- the volatility and uncertainty of regional pricing differentials;
- governmental regulations and taxation;
- energy conservation and environmental measures; and
- acts of force majeure.

Lower oil and natural gas prices will reduce profits to which the Trust is entitled and may ultimately reduce the amount of oil and natural gas that is economically viable to produce from the Underlying Properties. As a result, the operators of the Underlying Properties could determine during periods of low commodity prices to shut-in or curtail production from wells on the Underlying Properties, or even plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, an operator may abandon any well or property if it reasonably believes that the well or property can no longer produce oil or natural gas in commercially paying quantities. This could result in termination of the Net Profits Interest relating to the abandoned well or property.

The Underlying Properties are sensitive to decreasing commodity prices. The commodity price sensitivity is due to a variety of factors that vary from well to well, including the costs associated with water handling and disposal, chemicals, surface equipment maintenance, downhole casing repairs and reservoir pressure maintenance activities that are necessary to maintain production. As a result, decreasing commodity prices may cause the expenses of certain wells to exceed the well's revenue, in which case the operator may decide to shut-in the well or plug and abandon the well. This scenario could reduce future cash distributions to Trust unitholders.

The Sponsor has not entered into any hedge contracts relating to oil and natural gas volumes expected to be produced, and the terms of the Conveyance of the Net Profits Interest prohibit the Sponsor from entering into new hedging arrangements burdening the Trust. As a result, all production in which the Trust has an interest is unhedged, and the amount of the cash distributions is subject to the possibility of greater fluctuations due to changes in oil and natural gas prices.

Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the Trust and the value of the Trust Units.

The value of the Trust Units and the amount of future cash distributions to the Trust unitholders will depend upon, among other things, the accuracy of the reserves and future production estimated to be attributable to the Trust's interest in the Underlying Properties. It is not possible to measure underground accumulations of oil and natural gas in an exact way, and estimating reserves is inherently uncertain. Ultimately, actual production and revenues for the Underlying Properties could vary both positively and negatively and in material amounts from estimates. Furthermore, direct operating expenses and development expenses relating to the Underlying Properties could be substantially higher than current estimates. Petroleum engineers are required to make subjective estimates of underground accumulations of oil and natural gas based on factors and assumptions that include:

- historical production from the area compared with production rates from other producing areas;
- oil and natural gas prices, production levels, Btu content, production expenses, transportation costs, severance and excise taxes and development expenses; and
- the assumed effect of expected governmental regulation and future tax rates.

Changes in these assumptions and amounts of actual direct operating expenses and development expenses could materially decrease reserve estimates. In addition, the quantities of recovered reserves attributable to the Underlying Properties may decrease in the future as a result of future decreases in the price of oil or natural gas.

The reserve report estimating the Trust's proved reserves, future production and income attributable to the Trust's interests in the Underlying Properties as of December 31, 2018 was prepared, in accordance with applicable regulations, using an average of the NYMEX first-day-of-the-month commodity price during the 12-month period ending on December 31, 2018 as required by the SEC. The applicable prices for 2018 were $65.56 per Bbl of oil and $3.10 per Mcf of natural gas.

Third party operators are the operators of substantially all of the wells on the Underlying Properties and, therefore, the Sponsor is not in a position to control the timing of development efforts, the associated costs or the rate of production of the reserves on such properties.

As of December 31, 2018, substantially all of the wells on the Underlying Properties were operated by third party operators. As a result, the Sponsor has limited ability to exercise influence over, and control the risks or costs associated with, the operations of these properties. The failure of a third party operator to adequately or efficiently perform operations, a third party operator's breach of the applicable operating agreements or a third party operator's failure to act in ways that are in the Sponsor's or the Trust's best interests could reduce production and revenues. Further, none of the third party operators of the Underlying Properties is obligated to undertake any development activities, so any development and production activities will be subject to their reasonable discretion. The success and timing of drilling and development activities on properties operated by the third party operators, therefore, depends on a number of factors that will be largely outside of the Sponsor's control, including:

- the timing and amount of capital expenditures, which could be significantly more than anticipated;
- the availability of suitable drilling equipment, production and transportation infrastructure and qualified operating personnel;
- the third party operators' expertise, operating efficiency and financial resources;
- approval of other participants in drilling wells;
- the selection of technology;
- the selection of counterparties for the sale of production; and
- the rate of production of the reserves.

The third party operators may elect not to undertake development activities, or may undertake such activities in an unanticipated fashion, which may result in significant fluctuations in capital expenditures and amounts available for distribution to Trust unitholders.

Following the Sale Transaction, some third-party operators of the Underlying Properties have encountered delays in transitioning their reporting processes from Enduro to the Sponsor. As a result of such delays, production and revenues with respect to certain periods may be lower than expected, which would adversely affect amounts available for distribution to unitholders during this transition period. As delayed payments are received by the Sponsor, amounts available for distribution to unitholders may increase in certain months; however, such increased amounts would not be indicative of distributions that may be received in the future.

Developing oil and natural gas wells and producing oil and natural gas are costly and high-risk activities with many uncertainties that could adversely affect future production from the Underlying Properties. Any delays, reductions or cancellations in development and producing activities could decrease revenues that are available for distribution to Trust unitholders.

The process of developing oil and natural gas wells and producing oil and natural gas on the Underlying Properties is subject to numerous risks beyond the Trust's, the Sponsor's and the third party operators' control, including risks that could delay the operators' current drilling or production schedule and the risk that drilling will not result in commercially viable oil or natural gas production. The ability of the operators to carry out operations or to finance planned development expenses could be materially and adversely affected by any factor that may curtail, delay, reduce or cancel development and production, including:

- reductions in oil or natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements, including permitting;
- unusual or unexpected geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- equipment malfunctions, failures or accidents;
- unexpected operational events and drilling conditions;
- market limitations for oil or natural gas;
- pipe or cement failures;
- casing collapses;
- lost or damaged drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil and natural gas, inert gas, water or drilling fluids;
- fires and natural disasters;

- environmental hazards, such as oil and natural gas leaks, pipeline ruptures and discharges of toxic gases;
- adverse weather conditions; and
- oil or natural gas property title problems.

If planned operations, including drilling of development wells, are delayed or cancelled, or if existing wells or development wells experience production below anticipated levels due to one or more of the foregoing factors or for any other reason, estimated future distributions to Trust unitholders may be reduced. If an operator incurs increased costs due to one or more of the foregoing factors or for any other reason and is unable to recover such costs from insurance, estimated future distributions to Trust unitholders may be reduced.

The Trust is passive in nature and neither the Trust nor the Trust unitholders have any ability to influence the Sponsor or control the operations or development of the Underlying Properties.

The Trust Units are a passive investment that entitles the Trust unitholder to only receive cash distributions from the Net Profits Interest. Trust unitholders have no voting rights with respect to the Sponsor and, therefore, have no managerial, contractual or other ability to influence the Sponsor's or the third party operators' activities or the operations of the Underlying Properties. Oil and natural gas properties are typically managed pursuant to an operating agreement among the working interest owners of oil and natural gas properties. Third party operators operate substantially all of the wells on the Underlying Properties. The typical operating agreement contains procedures whereby the owners of the working interests in the property designate one of the interest owners to be the operator of the property. Under these arrangements, the operator is typically responsible for making all decisions relating to drilling activities, sale of production, compliance with regulatory requirements and other matters that affect the property.

Shortages of equipment, services and qualified personnel could increase costs of developing and operating the Underlying Properties and result in a reduction in the amount of cash available for distribution to the Trust unitholders.

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could hinder the ability of the operators of the Underlying Properties to conduct the operations which they currently have planned for the Underlying Properties, which would reduce the amount of cash received by the Trust and available for distribution to the Trust unitholders.

The Trust Units may lose value as a result of title deficiencies with respect to the Underlying Properties.

Enduro acquired the Underlying Properties through various acquisitions in late 2010 and early 2011. The Sponsor acquired Enduro's interests in the Underlying Properties pursuant to the Sale Transaction that closed in August 2018. The existence of a material title deficiency with respect to the Underlying Properties could reduce the value of a property or render it worthless, thus adversely affecting the Net Profits Interest and the distributions to Trust unitholders. The Sponsor does not obtain title insurance covering mineral leaseholds, and the Sponsor's failure to cure any title defects may cause the Sponsor to lose its rights to production from the Underlying Properties. If a material title problem were to arise, profits available for distribution to Trust unitholders, and the value of the Trust Units, may be reduced.

The Sponsor may transfer all or a portion of the Underlying Properties at any time without Trust unitholder consent, subject to specified limitations.

The Sponsor at any time may transfer all or part of the Underlying Properties, subject to and burdened by the Net Profits Interest, and may, along with the third party operators, abandon individual wells or properties reasonably believed to be not economically viable. Trust unitholders will not be entitled to vote on any transfer or abandonment of the Underlying Properties, and the Trust will not receive any profits from any such transfer, except in the limited circumstances when the Net Profits Interest is released in connection with such transfer, in which case the Trust will receive an amount equal to the fair market value (net of sales costs) of the Net Profits Interest released. Following any sale or transfer of any of the Underlying Properties, if the Net Profits Interest is not released in connection with such sale or transfer, the Net Profits Interest will continue to burden the transferred property and net profits attributable to such property will be calculated as part of the computation of net profits. The Sponsor may delegate to the transferee responsibility for all of the Sponsor's obligations relating to the Net Profits Interest on the portion of the Underlying Properties transferred.

In addition, the Sponsor may, without the consent of the Trust unitholders, require the Trustee to release the Net Profits Interest associated with any lease that accounts for 0.25% or less of the total production from the Underlying Properties in the prior 12 months and provided that the Net Profits Interest covered by such releases cannot exceed, during any 12-month period, an aggregate fair market value to the Trust of $500,000. These releases will be made only in connection with a sale by the Sponsor to a non-affiliate of the relevant Underlying Properties and are conditioned upon an amount equal to the fair market value of such Net Profits Interest being treated as an offset amount against costs and expenses. In January 2019, the Sponsor sold two producing wells and associated acreage of the Underlying Properties under this provision for a sale price of approximately $62,000, and the Trustee released such properties from the Net Profits Interest

The third party operators and the Sponsor may enter into farm-out, operating, participation and other similar agreements to develop the property without the consent or approval of the Trustee or any Trust unitholder.

The reserves attributable to the Underlying Properties are depleting assets and production from those reserves will diminish over time. Furthermore, the Trust is precluded from acquiring other oil and natural gas properties or net profits interests to replace the depleting assets and production. Therefore, proceeds to the Trust and cash distributions to Trust unitholders will decrease over time.

The profits payable to the Trust attributable to the Net Profits Interest are derived from the sale of production of oil and natural gas from the Underlying Properties. The reserves attributable to the Underlying Properties are depleting assets, which means that the reserves and the quantity of oil and natural gas produced from the Underlying Properties will decline over time.

Future maintenance projects on the Underlying Properties may affect the quantity of proved reserves that can be economically produced from wells on the Underlying Properties. The timing and size of these projects will depend on, among other factors, the market prices of oil and natural gas. Neither the Sponsor nor, to the Sponsor's knowledge, the third party operators have a contractual obligation to develop or otherwise pay development expenses on the Underlying Properties in the future. Furthermore, with respect to properties for which the Sponsor is not designated as the operator, the Sponsor has limited control over the timing or amount of those development expenses. The Sponsor also has the right to non-consent and not participate in the development expenses on properties for which it is not the operator, in which case the Sponsor and the Trust will not receive the production resulting from such development expenses. If the operators of the Underlying Properties do not implement maintenance projects when warranted, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Sponsor or estimated in the reserve report.

The Trust Agreement provides that the Trust's activities are limited to owning the Net Profits Interest and any activity reasonably related to such ownership, including activities required or permitted by the terms of the Conveyance related to the Net Profits Interest. As a result, the Trust is not permitted to acquire other oil and natural gas properties or net profits interests to replace the depleting assets and production attributable to the Net Profits Interest.

Because the net profits payable to the Trust are derived from the sale of depleting assets, the portion of the distributions to Trust unitholders attributable to depletion may be considered to have the effect of a return of capital as opposed to a return on investment. Eventually, the Underlying Properties burdened by the Net Profits Interest may cease to produce in commercially paying quantities and the Trust may, therefore, cease to receive any distributions of net profits therefrom. At that point the value of the Trust Units should be expected to be $0.

An increase in the differential between the price realized by the Sponsor for oil or natural gas produced from the Underlying Properties and the NYMEX or other benchmark price of oil or natural gas could reduce the profits to the Trust and, therefore, the cash distributions by the Trust and the value of Trust Units.

The prices received for the Sponsor's oil and natural gas production usually fall below the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the price received and the benchmark price is called a basis differential. The differential may vary significantly due to market conditions, the quality and location of production and other factors. The Sponsor cannot accurately predict oil or natural gas differentials. Increases in the differential between the realized price of oil and natural gas and the benchmark price for oil and natural gas could reduce the profits to the Trust, the cash distributions by the Trust and the value of the Trust Units.

The amount of cash available for distribution by the Trust will be reduced by the amount of any costs and expenses related to the Underlying Properties and other costs and expenses incurred by the Trust.

The Trust will indirectly bear an 80% share of all costs and expenses related to the Underlying Properties, such as direct operating and development expenses, which will reduce the amount of cash received by the Trust and thereafter distributable to Trust unitholders. Accordingly, higher costs and expenses related to the Underlying Properties will directly decrease the amount of cash received by the Trust in respect of its Net Profits Interest. Historical costs may not be indicative of future costs. For example, the third party operators may in the future propose additional drilling projects that significantly increase the capital expenditures associated with the Underlying Properties, which could reduce cash available for distribution by the Trust. In addition, cash available for distribution by the Trust will be further reduced by the Trust's general and administrative expenses.

If direct operating and development expenses on the Underlying Properties together with the other costs exceed gross profits of production from the Underlying Properties, the Trust will not receive net profits from those properties until future gross profits from production exceed the total of the excess costs, plus accrued interest at the prime rate. If the Trust does not receive net profits pursuant to the Net Profits Interest, or if such net profits are reduced, the Trust will not be able to distribute cash to the Trust unitholders, or such cash distributions will be reduced, respectively. Development activities may not generate sufficient additional revenue to repay the costs.

The generation of profits for distribution by the Trust depends in part on access to and operation of gathering, transportation and processing facilities. Any limitation in the availability of those facilities could interfere with sales of oil and natural gas production from the Underlying Properties.

The amount of oil and natural gas that may be produced and sold from a well is subject to curtailment in certain circumstances, such as by reason of weather conditions, pipeline interruptions due to scheduled and unscheduled maintenance, failure of tendered oil and natural gas to meet quality specifications of gathering lines or downstream transporters, excessive line pressure which prevents delivery, physical damage to the gathering system or transportation system or lack of contracted capacity on such systems. The curtailments may vary from a few days to several months. In many cases, the operators of the Underlying Properties receive only limited notice, if any, as to when production will be curtailed and the duration of such curtailments. If the operators of the Underlying Properties are forced to reduce production due to such a curtailment, the revenues of the Trust and the amount of cash distributions to the Trust unitholders similarly would be reduced due to the reduction of profits from the sale of production.

Under certain circumstances, the Trustee must sell the Net Profits Interest and dissolve the Trust prior to the expected termination of the Trust. As a result, Trust unitholders may not recover their investment.

The Trustee must sell the Net Profits Interest and dissolve the Trust if the holders of at least 75% of the outstanding Trust Units approve the sale or vote to dissolve the Trust. The Trustee must also sell the Net Profits Interest and dissolve the Trust if the annual cash proceeds received by the Trust attributable to the Net Profits Interest are less than $2 million for each of any two consecutive years. The net profits of any such sale will be distributed to the Trust unitholders.

The Sponsor may sell Trust Units in the public or private markets, and such sales could have an adverse impact on the trading price of the Trust Units.

The Sponsor holds an aggregate of 8,600,000 Trust Units. The Sponsor may sell Trust Units in the public or private markets, and any such sales could have an adverse impact on the price of the Trust Units. The Trust has granted registration rights to the Sponsor, which, if exercised, would facilitate sales of Trust Units by the Sponsor.

The trading price for the Trust Units may not reflect the value of the Net Profits Interest held by the Trust.

The trading price for publicly traded securities similar to the Trust Units tends to be tied to recent and expected levels of cash distributions. The amounts available for distribution by the Trust vary in response to numerous factors outside the control of the Trust, including prevailing prices for sales of oil and natural gas production from the Underlying Properties and the timing and amount of direct operating expenses and development expenses. Consequently, the market price for the Trust Units may not necessarily be indicative of the value that the Trust would realize if it sold the Net Profits Interest to a third-party buyer. In addition, the market price may not necessarily reflect the fact that since the assets of the Trust are depleting assets, a portion of each cash distribution paid with respect to the Trust Units should be considered by investors as a return of capital, with the remainder being considered as a return on investment. As a result, distributions made to a Trust unitholder over the life of these depleting assets may not equal or exceed the purchase price paid by the Trust unitholder.

Conflicts of interest could arise between the Sponsor and its affiliates, on the one hand, and the Trust and the Trust unitholders, on the other hand.

As working interest owners in, and the operators of certain wells on, the Underlying Properties, the Sponsor and its affiliates could have interests that conflict with the interests of the Trust and the Trust unitholders. For example:

- The Sponsor's interests may conflict with those of the Trust and the Trust unitholders in situations involving the development, maintenance, operation or abandonment of certain wells on the Underlying Properties for which the Sponsor acts as the operator. The Sponsor also may make decisions with respect to development expenses that adversely affect the Underlying Properties. These decisions include reducing development expenses on properties for which the Sponsor acts as the operator, which could cause oil and natural gas production to decline at a faster rate and thereby result in lower cash distributions by the Trust in the future.

- The Sponsor may sell some or all of the Underlying Properties without taking into consideration the interests of the Trust unitholders. Such sales may not be in the best interests of the Trust unitholders. These purchasers may lack the Sponsor's experience or its creditworthiness. The Sponsor also has the right, under certain circumstances, to cause the Trustee to release all or a portion of the Net Profits Interest in connection with a sale of a portion of the Underlying Properties to which such Net Profits Interest relates. In such an event, the Trust is entitled to receive the fair value (net of sales costs) of the Net Profits Interest released.

- The Sponsor may sell its Trust Units without considering the effects such sale may have on Trust Unit prices or on the Trust itself. Additionally, the Sponsor can vote its Trust Units in its sole discretion without considering the interests of the other Trust unitholders. The Sponsor is not a fiduciary with respect to the Trust unitholders or the Trust and does not owe any fiduciary duties or liabilities to the Trust unitholders or the Trust.

The Trust is administered by a Trustee who cannot be replaced except by a majority vote of the Trust unitholders at a special meeting which may make it difficult for Trust unitholders to remove or replace the Trustee.

The affairs of the Trust are administered by the Trustee. The voting rights of a Trust unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Trust unitholders or for an annual or other periodic re-election of the Trustee. The Trust Agreement provides that the Trustee may only be removed and replaced by the holders of a majority of the Trust Units present in person or by proxy at a meeting of such holders where a quorum is present, including Trust Units held by the Sponsor, called by either the Trustee or the holders of not less than 10% of the outstanding Trust Units. As a result, it will be difficult for public Trust unitholders to remove or replace the Trustee without the cooperation of holders of a significant percentage of total Trust Units.

Trust unitholders have limited ability to enforce provisions of the Net Profits Interest, and the Sponsor's liability to the Trust is limited.

The Trust Agreement permits the Trustee to sue the Sponsor or any other future owner of the Underlying Properties to enforce the terms of the Conveyance creating the Net Profits Interest. If the Trustee does not take appropriate action to enforce provisions of the Conveyance, Trust unitholders' recourse would be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. The Trust Agreement expressly limits a Trust unitholder's ability to directly sue the Sponsor or any other third party other than the Trustee. As a result, Trust unitholders will not be able to sue the Sponsor or any future owner of the Underlying Properties to enforce these rights. Furthermore, the Conveyance provides that, except as set forth in the Conveyance, the Sponsor will not be liable to the Trust for the manner in which it performs its duties in operating the Underlying Properties as long as it acts without gross negligence or willful misconduct.

Courts outside of Delaware may not recognize the limited liability of the Trust unitholders provided under Delaware law.

Under the Delaware Statutory Trust Act, Trust unitholders will be entitled to the same limitation of personal liability extended to stockholders of corporations for profit under the General Corporation Law of the State of Delaware. The courts in jurisdictions outside of Delaware, however, might not give effect to such limitation.

The operations of the Underlying Properties are subject to environmental laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations on them or result in significant costs and liabilities, which could reduce the amount of cash available for distribution to Trust unitholders.

The oil and natural gas exploration and production operations on the Underlying Properties are subject to stringent and comprehensive federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that apply to the operations on the Underlying Properties, including the requirement to obtain a permit before conducting drilling, waste disposal or other regulated activities; the restriction of types, quantities and concentrations of materials that can be released into the environment; restrictions on water withdrawal and use; the incurrence of significant development expenses to install pollution or safety-related controls at the operated facilities; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and the imposition of substantial liabilities for pollution resulting from operations. For example, the EPA has published regulations that impose more stringent emissions control requirements for oil and gas development and production operations, which may require us, our operators, or third-party contractors to incur additional expenses to control air emissions from current operations and during new well developments by installing emissions control technologies and adhering to a variety of work practice and other requirements. For example, in 2012 the EPA adopted federal New Source Performance Standards ("NSPS") that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. In June 2016, the EPA published a final rule adopting additional NSPS requirements for new, modified, or reconstructed oil and gas facilities that require control of the greenhouse gas methane from affected facilities, including requirements to find and repair fugitive leaks of methane emissions at well sites ("Methane Rule"). Following the 2016 presidential election and change in administrations, in 2017 the EPA proposed to delay implementation of the Methane Rule and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been (or are likely to be) challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require the Sponsor to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from its operations, which could reduce the profits available to the Trust and potentially impair the economic development of the Underlying Properties. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, often times requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of the operations on the Underlying Properties. Furthermore, the inability to comply with environmental laws and regulations in a cost-effective manner, such as removal and disposal of produced water and other generated oil and gas wastes, could impair the operators' ability to produce oil and natural gas commercially from the Underlying Properties, which would reduce profits attributable to the Net Profits Interest.

There is inherent risk of incurring significant environmental costs and liabilities in the operations on the Underlying Properties as a result of the handling of petroleum hydrocarbons and wastes, air emissions and wastewater discharges related to operations, and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, the operators could be subject to joint and several strict liability for the removal or remediation of previously released materials or property contamination regardless of whether such operators were responsible for the release or contamination or whether the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which wells are drilled and facilities where petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases could expose the operators of the Underlying Properties to significant liabilities that could have a material adverse effect on the operators' businesses, financial condition and results of operations and could reduce the amount of cash available for distribution to Trust unitholders. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly operational control requirements or waste handling, storage, transport, disposal or cleanup requirements could require the operators of the Underlying Properties to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on their results of operations, competitive position or financial condition.

The Trust will indirectly bear 80% of all costs and expenses paid by the Sponsor, including those related to environmental compliance and liabilities associated with the Underlying Properties, including costs and liabilities resulting from conditions that existed prior to the Sponsor's acquisition of the Underlying Properties unless such costs and expenses result from the operator's negligence or misconduct. In addition, as a result of the increased cost of compliance, the operators of the Underlying Properties may decide to discontinue drilling.

Neither the Sponsor nor the Trust is generally entitled to, nor required to provide, indemnity to third party operators with respect to pollution liability and associated environmental remediation costs. However, the Sponsor may be required to provide, and may be entitled to, indemnity from third party operators with respect to such liabilities and costs in the event of the other party's gross negligence or misconduct. In addition, the Sponsor, as the assignee of Enduro, has agreed to assume certain environmental liabilities of prior owners of the Underlying Properties in connection with the purchase thereof.

The amount of cash available for distribution by the Trust could be reduced by expenses caused by uninsured claims.

The Sponsor maintains insurance coverage against potential losses that it believes is customary in its industry. The Sponsor currently maintains general liability insurance and excess liability coverage. The Sponsor's excess liability coverage and general liability insurance do not have deductibles. The general liability insurance covers the Sponsor and its subsidiaries for legal and contractual liabilities arising out of bodily injury or property damage, including any resulting loss of use to third parties, and for sudden and accidental pollution or environmental liability, while the excess liability coverage is in addition to and triggered if the general liability per occurrence limit is reached. In addition, the Sponsor maintains control of well insurance with per occurrence limits depending on the status of the well and deductibles consistent with industry standards. The Sponsor's general liability insurance and excess liability policies do not provide coverage with respect to legal and contractual liabilities of the Trust, and the Trust does not maintain such coverage since it is passive in nature and does not have any ability to influence the Sponsor or control the operations or development of the Underlying Properties. However, the Trust unitholders may indirectly benefit from the Sponsor's insurance coverage to the extent that insurance proceeds offset or reduce any costs or expenses that are deducted when calculating the net profits attributable to the Trust.

The Sponsor does not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, the Sponsor believes its general liability and excess liability insurance policies would cover third-party claims related to hydraulic fracturing operations in accordance with, and subject to, the terms of such policies. These policies may not cover fines, penalties or costs and expenses related to government-mandated cleanup of pollution. In addition, these policies do not provide coverage for all liabilities, and there can be no assurance that the insurance coverage will be adequate to cover claims that may arise or that the Sponsor will be able to maintain adequate insurance at rates it considers reasonable. The occurrence of an event not fully covered by insurance could result in a significant decrease in the amount of cash available for distribution by the Trust. The Trust does not maintain any type of insurance against any of the risks of conducting oil and gas exploration and production, hydraulic fracturing operations, or related activities.

The operations on the Underlying Properties are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting operations on them or expose the operator to significant liabilities, which could reduce the amount of cash available for distribution to Trust unitholders.

The production and development operations on the Underlying Properties are subject to complex and stringent laws and regulations. To conduct their operations in compliance with these laws and regulations, the operators of the Underlying Properties must obtain and maintain numerous permits, drilling bonds, approvals and certificates from various federal, state and local governmental authorities and engage in extensive reporting. The operators of the Underlying Properties may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations, and the Trust will bear an 80% share of these costs. In addition, the operators' costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to their operations. Such costs could have a material adverse effect on the operators' business, financial condition and results of operations and reduce the amount of cash received by the Trust in respect of the Net Profits Interest. The operators of the Underlying Properties must also comply with laws and regulations prohibiting fraud and market manipulations in energy markets. To the extent the operators of the Underlying Properties are shippers on interstate pipelines, they must comply with the tariffs of such pipelines and with federal policies related to the use of interstate capacity, and such compliance costs will be borne in part by the Trust.

Laws and regulations governing exploration and production may also affect production levels. The operators of the Underlying Properties are required to comply with federal and state laws and regulations governing conservation matters, including: provisions related to the unitization or pooling of the oil and natural gas properties; the establishment of maximum rates of production from wells; the spacing of wells; the plugging and abandonment of wells; and the removal of related production equipment. Additionally, state and federal regulatory authorities may expand or alter applicable pipeline safety laws and regulations, compliance with which may require increase capital costs on the part of the operators and third party downstream natural gas transporters. These and other laws and regulations can limit the amount of oil and natural gas the operators can produce from their wells, limit the number of wells they can drill, or limit the locations at which they can conduct drilling operations, which in turn could negatively impact Trust distributions, estimated and actual future net revenues to the Trust and estimates of reserves attributable to the Trust's interests.

New laws or regulations, or changes to existing laws or regulations, may unfavorably impact the operators of the Underlying Properties and result in increased operating costs or have a material adverse effect on their financial condition and results of operations and reduce the amount of cash received by the Trust. For example, Congress is currently considering legislation that, if adopted in its proposed form, would subject companies involved in oil and natural gas exploration and production activities to, among other items, additional regulation of and restrictions on hydraulic fracturing of wells, the elimination of certain U.S. federal tax incentives and deductions available to oil and natural gas exploration and production activities and the prohibition or additional regulation of private energy commodity derivative and hedging activities. These and other potential regulations could increase the operating costs of the Underlying Properties, reduce the operators' liquidity, delay the operators' operations or otherwise alter the way the operators conduct their business, any of which could have a material adverse effect on the Trust and the amount of cash available for distribution to Trust unitholders.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that the operators produce while the physical effects of climate change could disrupt their production and cause them to incur significant costs in preparing for or responding to those effects.

The oil and gas industry is a direct source of certain greenhouse gas ("GHG") emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact future operations on the Underlying Properties. In December 2009, the EPA published its findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the Earth's atmosphere and other climate changes. Based on these findings, the agency has begun adopting and implementing regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted rules that regulate emissions of GHGs from certain large stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically are established by the states.

In June 2014, the U.S. Supreme Court held that GHG alone cannot trigger an obligation to obtain an air permit. However, the Supreme Court upheld EPA's authority to regulate GHG emissions from stationary sources, concluding sources that trigger air permitting requirements based on their traditional criteria pollutant emissions must include a limit for GHG in their permit. These EPA rules could affect the operations on the Underlying Properties or the ability of the operators of the Underlying Properties to obtain air permits for new or modified facilities.

In June 2016, the EPA published a final rule adopting New Source Performance Standards ("NSPS") for new, modified, or reconstructed oil and gas facilities that require control of the GHG methane from affected facilities, including requirements to find and repair fugitive leaks of methane emissions at well sites ("Methane Rule"). Following the 2016 presidential election and change in administrations, in 2017 the EPA proposed to delay implementation of the Methane Rule, and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been (or are likely to be) challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require the Sponsor to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from its operations.

In addition, in November 2016, the U.S. Department of the Interior Bureau of Land Management ("BLM") issued final rules to reduce methane emissions from venting, flaring, and leaks during oil and gas operations on federal and tribal lands that are substantially similar to the EPA's Methane Rule. However, on December 8, 2017, the BLM published a final rule to temporarily suspend or delay certain requirements contained in the November 2016 final rule until January 2019, including those requirements relating to venting, flaring and leakage from oil and gas production activities. Further, in September 2018, the BLM published a final rule to revise or rescind certain provisions of the 2016 rule. While the future implementation of the EPA and BLM rules aimed at controlling GHG emissions from oil and natural gas sources remains uncertain, future federal GHG regulations for the oil and gas industry remain a possibility given the long-term trend towards increasing regulation, and the Underlying Properties may be subject to these requirements or become subject to them in the future.

In addition, from time to time the U.S. Congress has from considered legislation to reduce emissions of GHGs, and many states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap -and -trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These reductions would be expected to cause the cost of allowances to escalate significantly over time. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from the equipment or operations of the operators of the Underlying Properties could require the operators to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with their operations. Such requirements could also adversely affect demand for the oil and natural gas produced, all of which could reduce profits attributable to the Net Profits Interest and, as a result, the Trust's cash available for distribution.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. Such developments may affect how these GHG initiatives will impact the operators of the Underlying Properties and the Trust.

Finally, some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on the operators' assets and operations and, consequently, may reduce profits attributable to the Net Profits Interest and, as a result, the Trust's cash available for distribution.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as adversely affect the services of the operators of the Underlying Properties.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over hydraulic fracturing. In December 2016 the EPA issued a final report on the potential impacts of hydraulic fracturing on drinking water resources. The report did not find widespread, systematic impacts to drinking water from hydraulic fracturing; at the same time, the report acknowledged information gaps that limited EPA's ability to fully assess the potential impacts to drinking water resources.

In 2012 the EPA adopted federal New Source Performance Standards ("NSPS") that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions." These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, and from pneumatic controllers and storage vessels. In June 2016, the EPA published a final rule adopting additional NSPS requirements for new, modified, or reconstructed oil and gas facilities that require control of the greenhouse gas methane from affected facilities, including requirements to find and repair fugitive leaks of methane emissions at well sites ("Methane Rule"). Following the 2016 presidential election and change in administrations, in 2017 the EPA proposed to delay implementation of the Methane Rule and also convened a reconsideration proceeding that resulted in two 2018 rulemaking projects aimed at rolling back certain Methane Rule requirements. These actions, like the Methane Rule itself, have been, or are likely to be, challenged in courts. The ultimate fate of the Methane Rule requirements is unclear. Nevertheless, regulations promulgated under the CAA may require the Sponsor to incur development expenses to install and utilize specific equipment, technologies, or work practices to control emissions from its operations, which could reduce the profits available to the Trust and potentially impair the economic development of the Underlying Properties.

Some states have adopted, and other states are considering adopting, regulations that could restrict or impose additional requirements relating to hydraulic fracturing in certain circumstances, including the disclosure of information regarding the substances used in the hydraulic fracturing process. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. Disclosure of chemicals used in the fracturing process could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings against producers and service providers based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is regulated at the federal level, the Sponsor's and the third party operators' fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. In December 2014, the Governor of New York announced that the state would maintain its moratorium on hydraulic fracturing in the state. Further, some local governments, including in Texas, have imposed moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities. Similar measures might be considered or implemented in the jurisdictions in which the Underlying Properties are located.

If new laws or regulations that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in Texas, Louisiana or New Mexico, such legal requirements could make it more difficult or costly for the Sponsor or the third party operators to perform hydraulic fracturing activities and thereby could affect the determination of whether a well is commercially viable. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that the operators are ultimately able to produce in commercially paying quantities from the Underlying Properties, and could increase the cycle times and costs to receive permits, delay or possibly preclude receipt of permits in certain areas, impact water usage and waste water disposal and require air emissions, water usage and chemical additives disclosures.

The Sponsor's ability to perform its obligations to the Trust could be limited by restrictions under its debt agreements.

The Sponsor has various contractual obligations to the Trust under the Trust Agreement and Conveyance. Restrictions under the Sponsor's debt agreements, including certain covenants, financial ratios and tests, could impair its ability to fulfill its obligations to the Trust. The requirement that the Sponsor comply with these restrictive covenants and financial ratios and tests may materially adversely affect its ability to react to changes in market conditions, take advantage of business opportunities it believes to be desirable, obtain future financing, fund needed capital expenditures or withstand a continuing or future downturn in its business which may, in turn, impair the Sponsor's operations and its ability to perform its obligations to the Trust under the Trust Agreement and Conveyance. If the Sponsor is unable to perform its obligations to the Trust under the Trust Agreement or Conveyance, it could have a material adverse effect on the Trust.

The bankruptcy of the Sponsor or any of the third party operators could impede the operation of the wells and the development of the proved undeveloped reserves.

The value of the Net Profits Interest and the Trust's ultimate cash available for distribution will be highly dependent on the financial condition of the operators of the Underlying Properties. None of the operators of the Underlying Properties, including the Sponsor, has agreed with the Trust to maintain a certain net worth or to be restricted by other similar covenants.

The ability to develop and operate the Underlying Properties depends on the future financial condition and economic performance and access to capital of the operators of those properties, which in turn will depend upon the supply and demand for oil and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond the control of the Sponsor and the third party operators. The Sponsor is not a reporting company and is not required to file periodic reports with the SEC pursuant to the Exchange Act. Therefore, Trust unitholders do not have access to financial information about the Sponsor.

In the event of the bankruptcy of an operator of the Underlying Properties, the working interest owners in the affected properties will have to seek a new party to perform the development and the operations of the affected wells. The working interest owners may not be able to find a replacement driller or operator, and they may not be able to enter into a new agreement with such replacement party on favorable terms within a reasonable period of time. As a result, such a bankruptcy may result in reduced production from the reserves and decreased distributions to Trust unitholders.

In the event of the bankruptcy of the Sponsor, if a court were to hold that the Net Profits Interest was part of the bankruptcy estate, the Trust may be treated as an unsecured creditor with respect to the Net Profits Interest attributable to properties in Louisiana and New Mexico.

The Sponsor and the Trust believe that, in a bankruptcy of the Sponsor, the Net Profits Interest would be viewed as a separate property interest under Texas law and, as such, outside of the Sponsor's bankruptcy estate. However, to the extent that were not the case, or to the extent Louisiana or New Mexico law were held to be applicable, the Net Profits Interest might be considered an asset of the bankruptcy estate and used to satisfy obligations to creditors of the Sponsor, in which case the Trust would be an unsecured creditor of the Sponsor at risk of losing the entire value of the Net Profits Interest to senior creditors.

Adverse developments in Texas, Louisiana or New Mexico could adversely impact the results of operations and cash flows of the Underlying Properties and reduce the amount of cash available for distributions to Trust unitholders.

The operations of the Underlying Properties are focused on the production and development of oil and natural gas within the states of Texas, Louisiana and New Mexico. As a result, the results of operations and cash flows of the Underlying Properties depend upon continuing operations in these areas. This concentration could disproportionately expose the Trust's interests to operational and regulatory risk in these areas. Due to the lack of diversification in geographic location, adverse developments in exploration and production of oil and natural gas in any of these areas of operation could have a significantly greater impact on the results of operations and cash flows of the Underlying Properties than if the operations were more diversified.

Cyber-attacks or other failures in telecommunications or information technology systems could result in information theft, data corruption and significant disruption of the Sponsor's business operations.

In recent years, the Sponsor has increasingly relied on information technology ("IT") systems and networks in connection with its business activities, including certain of its exploration, development and production activities. the Sponsor relies on digital technology, including information systems and related infrastructure, as well as cloud applications and services, to, among other things, estimate quantities of oil and natural gas reserves, analyze seismic and drilling information, process and record financial and operating data and communicate with employees and third parties. As dependence on digital technologies has increased, cyber incidents, including deliberate attacks and attempts to gain unauthorized access to computer systems and networks, have increased in frequency and sophistication. These threats pose a risk to the security of the Sponsor's systems and networks, the confidentiality, availability and integrity of its data and the physical security of its employees and assets. Any cyber-attack could have a material adverse effect on the Sponsor's reputation, competitive position, business, financial condition and results of operations, and could have a material adverse effect on the Trust. Cyber-attacks or security breaches also could result in litigation or regulatory action, as well as significant additional expense to the Sponsor to implement further data protection measures.

In addition to the risks presented to the Sponsor's systems and networks, cyber-attacks affecting oil and natural gas distribution systems maintained by third parties, or the networks and infrastructure on which they rely, could delay or prevent delivery to markets. A cyber-attack of this nature would be outside the Sponsor's ability to control, but could have a material adverse effect on the Sponsor's business, financial condition and results of operations, and could have a material adverse effect on the Trust.

Cyber-attacks or other failures in telecommunications or IT systems could result in information theft, data corruption and significant disruption of the Trustee's operations.

The Trustee depends heavily upon IT systems and networks in connection with its business activities. Despite a variety of security measures implemented by the Trustee, events such as the loss or theft of back-up tapes or other data storage media could occur, and the Trustee's computer systems could be subject to physical and electronic break-ins, cyber-attacks and similar disruptions from unauthorized tampering, including threats that may come from external factors, such as governments, organized crime, hackers and third parties to whom certain functions are outsourced, or may originate internally from within the respective companies.

If a cyber-attack were to occur, it could potentially jeopardize the confidential, proprietary and other information processed and stored in, and transmitted through, the Trustee's computer systems and networks, or otherwise cause interruptions or malfunctions in the operations of the Trust, which could result in litigation, increased costs and regulatory penalties. Although steps are taken to prevent and detect such attacks, it is possible that a cyber incident will not be discovered for some time after it occurs, which could increase exposure to these consequences.

TAX RISKS RELATED TO THE TRUST UNITS

The Trust has not requested a ruling from the IRS regarding the tax treatment of the Trust. If the IRS were to determine (and be sustained in that determination) that the Trust is not a "grantor trust" for U.S. federal income tax purposes, the Trust could be subject to more complex and costly tax reporting requirements that could reduce the amount of cash available for distribution to Trust unitholders.

If the Trust were not treated as a grantor trust for U.S. federal income tax purposes, the Trust should be treated as a partnership for such purposes. Although the Trust would not become subject to U.S. federal income taxation at the entity level as a result of treatment as a partnership, and items of income, gain, loss and deduction would flow through to the Trust unitholders, the Trust's tax reporting requirements would be more complex and costly to implement and maintain, and its distributions to Trust unitholders could be reduced as a result.

If the Trust were treated for U.S. federal income tax purposes as a partnership, it likely would be subject to new audit procedures that for taxable years beginning after December 31, 2017, alter the procedures for auditing large partnerships and also alter the procedures for assessing and collecting income taxes due (including applicable penalties and interest) as a result of an audit. These rules effectively would impose an entity level tax on the Trust, and unitholders may have to bear the expense of the adjustment even if they were not Trust unitholders during the audited taxable year.

Neither the Sponsor nor the Trustee has requested a ruling from the IRS regarding the tax status of the Trust, and neither the Sponsor nor the Trust can provide any assurance that such a ruling would be granted if requested or that the IRS will not challenge these positions on audit.

Trust unitholders should be aware of the possible state tax implications of owning Trust Units.

Unitholders are required to pay taxes on their share of the Trust's income even if they do not receive any cash distributions from the Trust.

Trust unitholders are treated as if they own the Trust's assets and receive the Trust's income and are directly taxable thereon as if no Trust were in existence. Because the Trust generates taxable income that could be different in amount than the cash the Trust distributes, unitholders are required to pay any U.S. federal income taxes and, in some cases, state and local income taxes on their share of the Trust's taxable income even if they receive no cash distributions from the Trust. A unitholder may not receive cash distributions from the Trust equal to such unitholder's share of the Trust's taxable income or even equal to the actual tax liability that results from that income.

A portion of any tax gain on the disposition of the Trust Units could be taxed as ordinary income.

If a unitholder sells Trust Units, he or she will recognize a gain or loss equal to the difference between the amount realized and his or her tax basis in those Trust Units. A substantial portion of any gain recognized may be taxed as ordinary income due to potential recapture items, including depletion recapture.

The Trust allocates its items of income, gain, loss and deduction between transferors and transferees of the Trust Units each month based upon the ownership of the Trust Units on the monthly record date, instead of on the basis of the date a particular Trust Unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among the Trust unitholders.

The Trust generally allocates its items of income, gain, loss and deduction between transferors and transferees of the Trust Units each month based upon the ownership of the Trust Units on the monthly record date, instead of on the basis of the date a particular Trust Unit is transferred. It is possible that the IRS could disagree with this allocation method and could assert that income and deductions of the Trust should be determined and allocated on a daily or prorated basis, which could require adjustments to the tax returns of the Trust unitholders affected by the issue and result in an increase in the administrative expense of the Trust in subsequent periods.

Trust unitholders should consult their tax advisors as to the specific tax consequences of the ownership and disposition of the of the Trust Units, including the applicability and effect of U.S. federal, state, local, and foreign income and other tax laws in light of their particular circumstances.

Item 1B. ***Unresolved Staff Comments.***

None.

Item 2. ***Properties.***

Description of the Underlying Properties

The Underlying Properties consist of producing and non-producing interests in oil and natural gas units, wells and lands in Texas, Louisiana and New Mexico. The Underlying Properties include a portion of the assets in east Texas and north Louisiana acquired by Enduro from Denbury Resources Inc. in December 2010, and all of the assets in the Permian Basin of New Mexico and west Texas acquired by Enduro from Samson Investment Company and ConocoPhillips Company in January 2011 and February 2011, respectively. In August 2018, the Sponsor purchased the Underlying Properties from Enduro and assumed all of Enduro's obligations under the Trust Agreement and other instruments to which Enduro and the Trustee were parties. The Underlying Properties are divided into two geographic regions: the Permian Basin region and East Texas/North Louisiana region.

As of December 31, 2018, the Underlying Properties had proved reserves of 18.4 MMBoe and 82% and 95% of the volumes and PV-10 value were attributable to proved developed reserves, respectively. Substantially all of the 18.4 MMBoe of proved reserves, based on PV-10 value, were operated by third-party operators.

The Sponsor's interests in the Underlying Properties require the Sponsor to bear its proportionate share of the costs of development and operation of such properties. As of December 31, 2018, the Sponsor held average working interests of approximately 21% and 17% and average net revenue interests of approximately 22% and 16% in the Underlying Properties located in the Permian Basin and East Texas/North Louisiana regions, respectively. The Underlying Properties are also burdened by non-cost bearing interests owned by third parties consisting primarily of overriding royalty and royalty interests.

Reserves

Cawley, Gillespie & Associates, Inc. ("Cawley Gillespie"), independent petroleum and geological engineers, estimated crude oil (including natural gas liquids) and natural gas proved reserves of the Underlying Properties' full economic life and for the Trust life as of December 31, 2018. Numerous uncertainties are inherent in estimating reserve volumes and values, and the estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of the reserves may vary significantly from the original estimates. In addition, the reserves and net revenues attributable to the Net Profits Interest include only 80% of the reserves attributable to the Underlying Properties that are expected to be produced within the term of the Net Profits Interest.

The independent petroleum engineer's report as to the proved oil and natural gas reserves as of December 31, 2018 was prepared by Cawley Gillespie. Cawley Gillespie, whose firm registration number is F-693, was founded in 1961 and is a leader in the evaluation of oil and gas properties. The technical person at Cawley Gillespie primarily responsible for overseeing the reserve estimates with respect to the Underlying Properties and the Net Profits Interest attributable to the Trust is W. Todd Brooker. Mr. Brooker has been a petroleum consultant for Cawley Gillespie since 1992 and is currently the Senior Vice President. He is a registered professional engineer in the State of Texas (license no. 83462) and a graduate of the University of Texas with a Bachelor of Science in Petroleum Engineering.

Information concerning changes in net proved reserves attributable to the Trust, and the calculation of the standardized measure of the related discounted future net revenues is contained in the notes to the financial statements of the Trust included in this Form 10-K. The Sponsor has not filed reserve estimates covering the Underlying Properties with any other federal authority or agency.

The following table summarizes the estimated proved reserve quantities and PV-10 attributable to the Trust and Underlying Properties as of December 31, 2018 and 2017:

	Trust Net Profits Interest				Underlying Properties			
	Oil(1)	Natural Gas	Total(2)	PV-10(3)	Oil(1)	Natural Gas	Total(2)	PV-10(3)
	(MBbls)	(MMcf)	(MBoe)	(in thousands)	(MBbls)	(MMcf)	(MBoe)	(in thousands)
2018								
Proved Developed Producing	3,954	9,656	5,563	$ 101,036	10,856	25,486	15,104	$ 126,295
Proved Developed Non-Producing	—	—	—	—	—	—	—	—
Proved Undeveloped	219	6,707	1,337	9,973	524	16,688	3,305	6,700
2017								
Proved Developed Producing	3,055	6,936	4,211	$ 66,094	9,882	21,422	13,453	$ 82,619
Proved Developed Non-Producing	—	14	2	30	1	38	7	37
Proved Undeveloped	42	82	56	818	148	290	196	1,022

(1) Reserves for natural gas liquids are immaterial and included as a component of oil reserves.
(2) Boe represents an approximate energy equivalent basis such that one Bbl of crude oil equals approximately six Mcf of natural gas. However, the value of oil and natural gas fluctuate and the value of reserve volumes of oil and natural gas are often substantially different than the amount implied by the Boe ratio.
(3) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows using the twelve-month unweighted arithmetic average of the first-day-of-the-month commodity prices, after adjustment for differentials in location and quality, for each of the preceding twelve months. An estimate of PV-10 is provided because it provides useful information to investors as it is widely used by professional analysts and sophisticated investors when evaluating oil and gas companies. PV-10 is considered relevant and useful for evaluating the relative monetary significance of oil and natural gas reserves. PV-10 is not intended to represent the current market value of the estimated reserves of the Underlying Properties. PV-10 differs from standardized measure of discounted future net cash flows because it does not include the effect of future income taxes. Please refer to the notes to the financial statements of the Trust included in this Form 10-K.

Reserve quantities and revenues for the Net Profits Interest were estimated from projections of reserves and revenues attributable to the Underlying Properties. Since the Trust has a defined Net Profits Interest, the Trust does not own a specific percentage of the oil and natural gas reserve quantities. Accordingly, reserves allocated to the Trust pertaining to its 80% Net Profits Interest in the Underlying Properties have effectively been reduced to reflect recovery of the Trust’s 80% portion of applicable production and development costs. Because Trust reserve quantities are determined using an allocation formula, any changes in actual or assumed prices or costs will result in revisions to the estimated reserve quantities allocated to the Net Profits Interest.

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Estimates of proved reserves were prepared in accordance with guidelines prescribed by the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions based upon an average of the NYMEX first-day-of-the-month commodity price during the 12-month period ending on the balance sheet date with no provision for price and cost escalations except by contractual arrangements. Prices used in estimating reserves were as follows:

	2018	2017	2016
Oil (per Bbl)	$ 65.56	$ 51.34	$ 42.75
Natural gas (per Mcf)	$ 3.10	$ 2.98	$ 2.48

Changes in Proved Undeveloped Reserves

During the year ended December 31, 2018, proved undeveloped reserves of the Underlying Properties increased 3,109 MMBoe due to an increase in the development of the Wolfcamp shale in the Permian Basin of west Texas and increasing activity in the Haynesville shale of Louisiana, as well as an increase in the average oil price used to estimate future net reserves. During 2018, 6 gross (0.5 net) wells were drilled and as a result of ongoing development activity, 10 gross (1.4 net) wells were added as proved undeveloped reserves at December 31, 2018. The following is a summary of the changes in quantities of proved undeveloped reserves for the Underlying Properties during the year ended December 31, 2018:

	Underlying Properties		
	Oil(1) (MBbls)	Natural Gas (MMcf)	Total (MBoe)
Balance — December 31, 2017	148	290	196
Development	376	16,398	3,109
Revisions and Other	—	—	—
Balance — December 31, 2018	524	16,688	3,305

(1) Reserves for natural gas liquids are immaterial and included as a component of oil reserves.

Producing Acreage and Well Counts

For the following data, “gross” refers to the total number of wells or acres in the Underlying Properties and “net” refers to gross wells or acres multiplied by the percentage working interest owned by the Sponsor and in turn attributable to the Underlying Properties. All of the acreage comprising the Underlying Properties is held by production. Although many wells produce both oil and natural gas, a well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas production.

The Underlying Properties are interests in properties located in the Permian Basin of west Texas and New Mexico and in the East Texas/North Louisiana region. The following is a summary of the approximate acreage of the Underlying Properties at December 31, 2018:

	Acres	
	Gross	Net
Permian Basin	123,367	36,580
East Texas/North Louisiana	12,629	4,899
Total	135,996	41,479

The following is a summary of the producing wells on the Underlying Properties as of December 31, 2018:

	Oil		Natural Gas	
	Gross Wells(1)	Net Wells	Gross Wells(1)	Net Wells
Permian Basin	3,356	691	94	20
East Texas/North Louisiana	—	—	298	64
Total	3,356	691	392	84

(1) The Sponsor’s total producing wells include 17 operated wells and 3,731 non-operated wells.

The following is a summary of the number of development and exploratory wells drilled on the Underlying Properties located in the Permian Basin and East Texas/North Louisiana during the last three years:

	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin						
Development Wells:						
Productive	6	0.5	8	1.3	9	0.9
Dry holes	—	—	—	—	—	—
	6	0.5	8	1.3	9	0.9
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
	—	—	—	—	—	—
Total:						
Productive	6	0.5	8	1.3	9	0.9
Dry holes	—	—	—	—	—	—
	6	0.5	8	1.3	9	0.9

	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
East Texas/North Louisiana						
Development Wells:						
Productive	—	—	6	0.5	—	—
Dry holes	—	—	—	—	—	—
	—	—	6	0.5	—	—
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
	—	—	—	—	—	—
Total:						
Productive	—	—	6	0.5	—	—
Dry holes	—	—	—	—	—	—
	—	—	6	0.5	—	—

Major Producing Areas

Substantially all of the Underlying Properties are located in mature oil fields that are characterized by long production histories. Based on the reserve reports, approximately 72% of the future production from the Underlying Properties is expected to be oil and approximately 28% is expected to be natural gas.

Permian Basin Region

The Permian Basin is one of the largest and most prolific oil and natural gas producing basins in the United States. The Underlying Properties in the Permian Basin contain 123,367 gross (36,580 net) acres in Texas and New Mexico.

The largest fields in the Underlying Properties are located primarily in the Permian Basin (measured by Boe reserves at December 31, 2018). Each of the following fields individually account for more than 15 percent of the Underlying Properties reserves as of December 31, 2018.

- The largest field area in the Permian Basin region is the Eunice Monument field, which primarily consists of the North Monument Grayburg Unit. The North Monument Grayburg Unit was discovered in 1929. Proved reserves attributable to the Underlying Properties in the Eunice Monument area were 2.4 MMBoe as of December 31, 2018. The operators of the Eunice Monument area are Apache Corporation and XTO Energy.

- The second largest field in the Permian Basin region is the Lost Tank field operated by Occidental Petroleum. This unit produces from the Brushy Canyon and Wolfcamp formations at depths up to 8,500 feet. Proved reserves attributable to the Underlying Properties in the Lost Tank field were 2.1 MMBoe as of December 31, 2018.

The following table shows the average sales price and lease operating expenses for any field that individually accounted for more than 15 percent of the Underlying Properties' reserves as of the end of the respective period. The figures presented for the largest fields in the Permian Basin of west Texas and New Mexico below relate to the amounts included in the net profits calculation for the distributions paid during the years ended December 31, 2018, 2017 and 2016.

		Year Ended December 31,		
		2018	2017	2016
Eunice Monument Area	Oil Average Sales Price per Bbl	$ 60.33	$ 46.09	$ 38.94
	Natural Gas Average Sales Price per Mcf	$ 3.62	$ 3.28	$ 2.65
	Average Lease Operating Expense per Boe	$ 19.86	$ 17.86	$ 18.53
Lost Tank	Oil Average Sales Price per Bbl	$ 58.85	$ 48.21	$ 37.57
	Natural Gas Average Sales Price per Mcf	$ 3.04	$ 2.72	$ 1.93
	Average Lease Operating Expense per Boe	$ 9.51	$ 4.46	$ 4.72

East Texas/North Louisiana Region

The Underlying Properties contain interests in 12,629 gross (4,899 net) acres in the East Texas/North Louisiana region across three fields: the Elm Grove field, operated primarily by Aethon Energy Operating, LLC and BHP Billiton Ltd.; the Kingston field, operated by EXCO Resources and Indigo Resources, LLC; and the Stockman field, operated by COERT. Substantially all proved reserves attributable to the Underlying Properties in the East Texas/North Louisiana region are located in the Haynesville, Cotton Valley, and Hosston reservoirs of the Elm Grove and Kingston fields. Proved reserves attributable to the Underlying Properties in the Elm Grove and Kingston fields were 3.7 MMBoe and 0.12 MMBoe, respectively, as of December 31, 2018.

Production and Reserves

The following table shows the net production, average sales price, average lease operating expense, and proved reserves as of year-end for the Underlying Properties located in the Permian Basin of west Texas and New Mexico and in the East Texas/North Louisiana region, which relates to the amounts included in the net profits calculation for the distributions paid during the years ended December 31, 2018, 2017, and 2016.

		Year Ended December 31,		
		2018	2017	2016
Permian Basin	Oil Sales Volumes (Bbls)	797,614	617,894	791,459
	Natural Gas(1) Sales Volumes (Mcf)	2,458,036	1,865,321	2,503,998
	Total Sales Volumes (Boe)	1,207,287	928,781	1,208,792
	Oil Average Sales Price per Bbl	$ 55.19	$ 46.30	$ 38.41
	Natural Gas Average Sales Price per Mcf	$ 3.12	$ 2.78	$ 2.04
	Average Lease Operating Expense per Boe	$ 26.11	$ 19.06	$ 16.59
	Proved Reserves (MBoe)	14,590	11,979	9,480
East Texas/North Louisiana	Oil Sales Volumes (Bbls)	2,616	3,922	4,937
	Natural Gas(1) Sales Volumes (Mcf)	2,543,104	1,320,851	1,993,351
	Total Sales Volumes (Boe)	426,467	224,064	337,162
	Oil Average Sales Price per Bbl	$ 50.09	$ 45.84	$ 37.23
	Natural Gas Average Sales Price per Mcf	$ 3.73	$ 2.74	$ 2.10
	Average Lease Operating Expense per Boe	$ 9.43	$ 8.40	$ 7.03
	Proved Reserves (MBoe)	3,819	1,677	672
Total	Oil Sales Volumes (Bbls)	800,230	621,816	796,396
	Natural Gas(1) Sales Volumes (Mcf)	5,001,140	3,186,172	4,497,349
	Total Sales Volumes (Boe)	1,633,754	1,152,845	1,545,954
	Oil Average Sales Price per Bbl	$ 55.04	$ 46.29	$ 38.40
	Natural Gas Average Sales Price per Mcf	$ 2.84	$ 2.76	$ 2.07
	Average Lease Operating Expense per Boe	$ 21.76	$ 16.98	$ 14.50
	Proved Reserves (MBoe)	18,409	13,656	10,152

(1) Production of natural gas liquids is immaterial and included as a component of natural gas production.

Abandonment and Sale of Underlying Properties

Each of the operators of the Underlying Properties or any transferee has the right to abandon its interest in any well or property if it reasonably believes a well or property ceases to produce or is not capable of producing in commercially paying quantities. Upon termination of the lease, the portion of the Net Profits Interest relating to the abandoned property will be extinguished.

The Sponsor generally may sell all or a portion of its interests in the Underlying Properties, subject to and burdened by the Net Profits Interest, without the consent of the Trust unitholders. Following the sale of all or any portion of the Underlying Properties, the purchaser will be bound by the obligations of the Sponsor under the Trust Agreement and the Conveyance with respect to the portion sold. In addition, the Sponsor may, without the consent of the Trust unitholders, require the Trustee to release the Net Profits Interest associated with any lease that accounts for less than or equal to 0.25% of the total production from the Underlying Properties in the prior 12 months and provided that the Net Profits Interest covered by such releases cannot exceed, during any 12-month period, an aggregate fair market value to the Trust of $500,000. These releases will be made only in connection with a sale by the Sponsor to a non-affiliate of the relevant Underlying Properties and are conditioned upon the Trust receiving an amount equal to the fair value to the Trust of such Net Profits Interest. In January 2019, the Sponsor sold two producing wells and associated acreage of the Underlying Properties under this provision for a sale price of approximately $62,000, and the Trustee released such properties from the Net Profits Interest

Title to Properties

The properties comprising the Underlying Properties are or may be subject to one or more of the burdens and obligations described below. To the extent that these burdens and obligations affect the Sponsor's rights to production or the value of production from the Underlying Properties, they have been taken into account in calculating the Trust's interests and in estimating the size and the value of the reserves attributable to the Underlying Properties.

The Sponsor's interests in the oil and natural gas properties comprising the Underlying Properties are typically subject to one or more of the following:

- royalties and other burdens, express and implied, under oil and natural gas leases and other arrangements;
- overriding royalties, production payments and similar interests and other burdens created by the Sponsor's predecessors in title;
- a variety of contractual obligations arising under operating agreements, farm-out agreements, production sales contracts and other agreements that may affect the Underlying Properties or their title;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing unpaid suppliers and contractors and contractual liens under operating agreements that are not yet delinquent or, if delinquent, are being contested in good faith by appropriate proceedings;
- pooling, unitization and communitization agreements, declarations and orders;
- easements, restrictions, rights-of-way and other matters that commonly affect property;
- conventional rights of reassignment that obligate the Sponsor to reassign all or part of a property to a third party if the Sponsor intends to release or abandon such property;
- preferential rights to purchase or similar agreements and required third party consents to assignments or similar agreements;
- obligations or duties affecting the Underlying Properties to any municipality or public authority with respect to any franchise, grant, license or permit, and all applicable laws, rules, regulations and orders of any governmental authority; and
- rights reserved to or vested in the appropriate governmental agency or authority to control or regulate the Underlying Properties and also the interests held therein, including the Sponsor's interests and the Net Profits Interest.

The Sponsor has informed the Trustee that the Sponsor believes the burdens and obligations affecting the properties comprising the Underlying Properties are conventional in the industry for similar properties. The Sponsor has also informed the Trustee that the Sponsor believes the existing burdens and obligations do not, in the aggregate, materially interfere with the use of the Underlying Properties and will not materially adversely affect the Net Profits Interest or its value.

To give third parties notice of the Net Profits Interest, Enduro recorded the Conveyance in Texas, Louisiana and New Mexico in the real property records in each Texas, Louisiana or New Mexico county in which the Underlying Properties are located, or in such other public records of those states as required under applicable law to place third parties on notice of the Conveyance.

In a bankruptcy of the Sponsor, to the extent Louisiana or New Mexico law were held to be applicable, the Net Profits Interest might be considered an asset of the bankruptcy estate and used to satisfy obligations to creditors of the Sponsor, in which case the Trust would be an unsecured creditor of the Sponsor at risk of losing the entire value of the Net Profits Interest to senior creditors. See "Risk Factors—In the event of the bankruptcy of the Sponsor, if a court were to hold that the Net Profits Interest was part of the bankruptcy estate, the Trust may be treated as an unsecured creditor with respect to the Net Profits Interest attributable to properties in Louisiana and New Mexico" in Item 1A of this Form 10-K.

The Sponsor believes that its title to the Underlying Properties and the Trust's title to the Net Profits Interest are each good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions as are not so material to detract substantially from the use or value of such Underlying Properties or Net Profits Interest. Under the terms of the Conveyance creating the Net Profits Interest, the Sponsor has provided a special warranty of title with respect to the Net Profits Interest, subject to the burdens and obligations described in this section. Please see "Risk Factors—The Trust Units may lose value as a result of title deficiencies with respect to the Underlying Properties" in Item 1A of this Form 10-K.

Item 3. ***Legal Proceedings.***

Currently, there are not any legal proceedings pending to which the Trust is a party or of which any of its property is the subject. The foregoing does not address any legal proceedings to which the Sponsor or any of the third-party operators may be a party or subject or that may otherwise relate to or affect any of the Underlying Properties or the operations of any of the operators of the Underlying Properties.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

Item 5. ***Market for Registrant's Trust Units, Related Unitholder Matters and Issuer Purchases of Trust Units.***

The Trust Units trade on the New York Stock Exchange under the symbol "PVL." At December 31, 2018, there were 33,000,000 Trust Units outstanding. On March 8, 2019, there were four unitholders of record. This number does not include owners for whom Trust Units may be held in "street" name.

Distributions

Each month, the Trustee determines the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Net Profits Interest and other sources (such as interest earned on any amounts reserved by the Trustee) that month, over the Trust's incurred expenses for that month. Available funds are reduced by any cash the Trustee decides to hold as a reserve against future liabilities. The holders of Trust Units as of the applicable record date (generally the last business day of each calendar month) are entitled to monthly distributions payable on or before the tenth business day after the record date (or the next succeeding business day). For further information on distributions to unitholders, see Note 7 of the Notes to Financial Statements in Item 8 of this Form 10-K.

Equity Compensation Plans

The Trust does not have any employees and does not maintain any equity compensation plans.

Recent Sales of Unregistered Securities

There were no equity securities sold by the Trust during the year ended December 31, 2018.

Purchases of Equity Securities

There were no purchases of Trust Units by the Trust or any affiliated purchaser during the fourth quarter of 2018.

Item 6. *Selected Financial Data.*

As a "smaller reporting company" as defined in Item 10(f)(1) of Regulation S-K, the Trust is not required to provide information required by this Item.

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

This discussion contains forward-looking statements. Please refer to "Forward-Looking Statements" for an explanation of these types of statements.

Overview

Permianville Royalty Trust, previously known as Enduro Royalty Trust, a statutory trust created in May 2011, completed its initial public offering in November 2011. The Trust's only asset and source of income is the Net Profits Interest, which entitles the Trust to receive 80% of the net profits from oil and natural gas production from the Underlying Properties. The Net Profits Interest is passive in nature and neither the Trust nor the Trustee has any management control over or responsibility for costs relating to the operation of the Underlying Properties. Additionally, third parties operate substantially all of the wells on the Underlying Properties and, therefore, the Sponsor is not in a position to control the timing of development efforts, associated costs, or the rate of production of the reserves.

The Trust is required to make monthly cash distributions of substantially all of its monthly cash receipts, after deducting the Trust's administrative expenses, to holders of record (generally the last business day of each calendar month) on or before the tenth business day after the record date. The Net Profits Interest is entitled to a share of the profits from and after July 1, 2011 attributable to production occurring on or after June 1, 2011. The amount of Trust revenues and cash distributions to Trust unitholders depends on, among other things:

- oil and natural gas sales prices;
- volumes of oil and natural gas produced and sold attributable to the Underlying Properties;
- production and development costs;
- price differentials;
- potential reductions or suspensions of production;
- the amount and timing of Trust administrative expenses; and
- the establishment, increase, or decrease of reserves for approved development expenses or future liabilities of the Trust.

Generally, the Sponsor receives cash payment for oil production 30 to 60 days after it is produced and for natural gas production 60 to 90 days after it is produced.

2018 Recap and 2019 Outlook

In July 2018, Enduro entered into a purchase and sale agreement with COERT Holdings 1 LLC ("COERT" or the "Sponsor") for the properties in which the Trust holds a net profits interest and all of the outstanding Trust Units owned by Enduro (the "Sale Transaction"), and on August 31, 2018, the parties closed the Sale Transaction. In connection with the Sale Transaction, COERT assumed all of Enduro's obligations under the Trust Agreement and other instruments to which Enduro and the Trustee were parties. COERT is a Delaware limited liability company engaged in the production and development of oil and natural gas from properties located in the Rockies, the Permian Basin of west Texas and southeastern New Mexico, and the Arklatex region of Texas and Louisiana.

The average realized oil and gas prices received for the production months included in 2018 distributions increased 19% and 3%, respectively, from the prior year as a result of the corresponding increase in the average NYMEX oil price and average NYMEX gas price for the relevant production months.

In 2018, development activity on the Underlying Properties was focused on the Permian Basin area. The increase in oil and natural prices along with technology improvements and multi-zone development have allowed operators to increase horizontal drilling activities in the Permian Basin. A significant majority of the capital expenditures incurred in 2018 were focused on the Permian Basin area, with six gross (0.5 net) wells drilled during 2018.

The operators of the properties underlying the Trust continue to evaluate planned capital expenditures during 2019, but based on currently available information, the Sponsor anticipates 2019 capital expenditures to range from $5 million to $7 million attributable to the properties in which the Trust owns a net profits interest, or $4 million to $6 million net to the Trust's 80% net profits interest.

Results of Operations

The following table displays oil and natural gas sales volumes and average prices from the Underlying Properties, representing the amounts included in the net profits calculation for the distributions paid during the years ended December 31, 2018, 2017, and 2016.

	Underlying Properties Sales Volumes		Average Price	
Month of Distribution	**Oil (Bbls)**	**Natural Gas (Mcf)**	**Oil (per Bbl)**	**Natural Gas (per Mcf)**
2018:				
January	180,603	876,698	$ 44.89	$ 2.84
February	52,890	353,764	$ 47.83	$ 2.87
March	62,006	410,091	$ 53.29	$ 2.87
April	58,843	480,736	$ 55.79	$ 2.73
May	59,699	397,208	$ 60.77	$ 2.87
June	52,534	359,703	$ 60.77	$ 2.92
July	59,985	395,489	$ 60.21	$ 3.02
August	55,566	394,953	$ 62.81	$ 2.50
September	58,110	400,200	$ 62.82	$ 2.58
October	56,432	423,439	$ 56.64	$ 2.73
November(1)	52,433	92,537	$ 59.71	$ 5.65
December	50,929	416,322	$ 57.19	$ 2.71
Total—2018(2)	**800,230**	**5,001,140**	$ **55.04**	**$ 2.84**
2017:				
January	61,130	257,711	$ 41.10	$ 2.41
February	63,737	261,379	$ 45.04	$ 2.63
March	60,632	471,853	$ 42.85	$ 2.61
April	74,925	308,189	$ 51.25	$ 2.50
May	62,978	306,811	$ 49.07	$ 3.05
June	57,714	305,783	$ 50.05	$ 3.48
July	63,106	291,314	$ 47.42	$ 3.01
August	59,930	309,909	$ 47.45	$ 2.48
September	59,033	358,085	$ 45.11	$ 2.71
October	58,631	315,138	$ 42.40	$ 2.78
Total—2017(3)	**621,816**	**3,186,172**	$ **46.29**	**$ 2.76**
2016:				
January	70,206	406,853	$ 44.37	$ 2.44
February	70,104	415,239	$ 45.03	$ 2.33
March	68,223	486,540	$ 40.28	$ 2.55
April	66,130	365,158	$ 33.55	$ 1.88
May	69,156	392,316	$ 29.06	$ 1.85
June	64,393	361,611	$ 27.89	$ 1.87
July	69,118	337,869	$ 33.32	$ 1.81
August	65,679	357,235	$ 36.44	$ 1.56
September	65,223	311,904	$ 42.20	$ 1.90
October	63,325	378,239	$ 45.24	$ 1.85
November	63,585	349,412	$ 41.83	$ 2.04
December	61,254	334,973	$ 41.85	$ 2.47
Total—2016	**796,396**	**4,497,349**	**$ 38.40**	**$ 2.07**

(1) In November 2018, due to reporting delays from operators associated with the transition of ownership from Enduro to the Sponsor, the average price of natural gas from the Underlying Properties is not comparable to other months presented.

(2) In 2017, there were two months in which direct operating and development expenses exceeded revenues, which resulted in negative net profits from the Underlying Properties for those periods. As a result, there were no distributions to Trust unitholders in November or December 2017, and the aggregate shortfall in net profits of $526,709 was carried forward to be deducted from future net profits generated by the Underlying Properties. In January 2018, net profits from the Underlying Properties were positive, and the aggregate shortfall was deducted from such net profits when calculating distributions paid in January 2018. As a result, sales volumes for November and December 2017 have been included in the sales volumes for January 2018.

(3) The year ended December 31, 2017 does not include sales volumes for November and December as the Trust did not pay a distribution in those months as the net profits interest calculation for such periods was negative.

Computation of Income from Net Profits Interest Received by the Trust

In connection with the closing of the initial public offering in November 2011, Enduro contributed the Net Profits Interest to the Trust in exchange for 33,000,000 newly issued Trust Units. The Net Profits Interest entitles the Trust to receive 80% of the net profits from the sale and production of oil and natural gas attributable to the Underlying Properties that are produced during the term of the Conveyance, which commenced on July 1, 2011. The Trust's Income from Net Profits Interest consists of monthly net profits attributable to the Income from Net Profits Interest. Net profits income for the years ended December 31, 2018, 2017, and 2016 was determined as shown in the following table:

	Year Ended December 31, 2018	2017	2016
Gross profits:			
Oil sales	$ 44,044,350	$ 28,785,847	$ 30,581,617
Natural gas sales	14,205,325	8,801,104	9,288,783
Total	58,249,675	37,586,951	39,870,400
Costs:			
Direct operating expenses:			
Lease operating expenses	28,055,000	19,580,000	22,422,000
Compression, gathering and transportation	2,749,000	2,026,000	3,179,000
Production, ad valorem and other taxes	4,740,000	2,707,000	2,953,000
Development expenses	3,649,000	3,844,000	(329,000)
Total	39,193,000	28,157,000	28,225,000
Net profits	$ 19,056,675	$ 9,429,251	$ 11,645,400
Less: General and administrative expenses paid by Enduro related to divestiture	(88,243)	—	—
Net profits after adjustments for divested properties	18,968,432	9,429,251	11,615,400
Percentage allocable to Net Profits Interest	80%	80%	80%
Net profits allocable to Net Profits Interest	$ 15,174,746	$ 7,543,960	$ 9,316,320
Sponsor Cash Reserve	12,035	—	—
Enduro/Sponsor reserve for approved development expenses released (withheld), net	—	100,000	(100,000)
Income from Net Profits Interest	15,186,781	7,643,960	9,216,320
Less: Trust general and administrative expenses and cash withheld for expenses	(1,583,777)	(850,052)	(730,040)
Distributable income generated by properties prior to divestiture	$ 13,603,004	$ 6,793,908	$ 8,486,280
Income from sale of Net Profits Interest	751,732	37,950,165	—
Distributable income	$ 14,354,736	$ 44,744,073	$ 8,486,280

In 2017, there were two months in which direct operating and development expenses exceeded revenues, thereby causing net profits on the Underlying Properties to be negative. As a result, there were no distributions to Trust unitholders in November or December 2017 and the aggregate shortfall in net profits of $526,709 was carried forward to be deducted from future net profits generated by the Underlying Properties in 2018. As the net profits for these two months in 2017 was negative and there was no distribution paid to unitholders, revenues and the associated direct operating and development expenses are excluded from the calculation of distributable income detailed in the table above for the year ended December 31, 2017 as well as the related sales volumes detailed below.

In January 2018, net profits from the Underlying Properties were positive, and the aggregate shortfall in net profits of $526,709 from November and December 2017 was deducted from such net profits when calculating distributions paid in January 2018. Since the 2017 shortfall in net profits was recovered in 2018 and included in 2018 distributions paid to unitholders, revenues and the associated direct operating and development expenses for November and December 2017 are included in the calculation of distributable income detailed in the table above for the year ended December 31, 2018 as well as the related sales volumes detailed below.

The following table displays oil and natural gas sales volumes and average prices from the Underlying Properties, representing the amounts included in the net profits calculation for distributions paid during the years ended December 31, 2018, 2017, and 2016:

	Year Ended December 31, 2018	2017	2016
Underlying Properties Sales Volumes:			
Oil (Bbls)	800,230	621,816	796,396
Natural Gas (Mcf)	5,001,140	3,186,172	4,497,349
Combined (Boe)	1,633,753	1,152,845	1,545,954
Average Prices:			
Oil — NYMEX (applicable NPI period) ($/Bbl)	$ 60.61	$ 49.35	$ 41.63
Differential	$ (5.57)	$ (3.06)	$ (3.23)
Oil prices realized ($/Bbl)	$ 55.04	$ 46.29	$ 38.40
Natural gas — NYMEX (applicable NPI period) ($/Mcf)	$ 2.89	$ 3.08	$ 2.30
Differential	$ (0.05)	$ (0.32)	$ (0.23)
Natural gas prices realized ($/Mcf)	$ 2.84	$ 2.76	$ 2.07

Years Ended December 31, 2018 and 2017

Net profits attributable to the Underlying Properties for the year ended December 31, 2018 is calculated from the following:

- oil sales related to oil produced from the Underlying Properties primarily from July 2017 through August 2018;
- natural gas sales related to natural gas produced from the Underlying Properties primarily from June 2017 through July 2018; and
- direct operating and development expenses related to expenses and capital incurred primarily from August 2017 to September 2018.

Net profits attributable to the Underlying Properties for the year ended December 31, 2018 were $19.1 million compared to $9.4 million for the year ended December 31, 2017. As a result of direct operating expenses and development expenses exceeding oil and natural gas sales for the last two months of 2017, the Trust did not pay a distribution to unitholders for the last two months of 2017. Under the modified cash basis of accounting, as there was no distribution, the oil and natural gas sales, direct operating expenses and development expenses for such periods are not included in the table above or this analysis of net profits attributable to the Underlying Properties for the year ended December 31, 2017 versus the year ended December 31, 2018. Therefore, several variances between years are due to the year ended December 31, 2018 including fourteen months of results compared to ten months for the year ended December 31, 2017. The $9.6 million increase from 2017 to 2018 was primarily due to the following items:

- Oil sales increased $15.2 million, primarily due to higher sales volumes, which increased oil sales by $8.3 million. The remaining $7.0 million increase in oil sales was due to higher realized prices. The average oil price received increased 19% as a result of the corresponding increase in the average NYMEX oil price for the relevant production months. Oil sales volumes increased 29% primarily due to the year ended December 31, 2018 including fourteen months of oil s including only ten months of oil sales volumes.

- Natural gas sales increased $5.4 million due to higher sales volumes, which increased natural gas sales by $5.0 million. The remaining $0.4 million increase in natural gas sales was due to higher realized prices. The average natural gas price received increased 3% as a result of the corresponding increases in the average NYMEX gas price for the relevant production months. Natural gas volumes increased 57% primarily because the year ended December 31, 2018 included fourteen months of gas sales volumes while the year ended December 31, 2017 included only ten months of gas sales volumes. During 2018, average monthly gas sales volumes increased 12% due to production volumes from six gross (0.45 net) wells in the Haynesville, which began production in September 2018.

- Compression, gathering and transportation (“CGT”) expenses increased from $2.0 million in 2017 to $2.8 million in 2018. The increase in CGT expenses is primarily attributable to the difference in the number of months included in the respective periods.

- Lease operating expenses increased $8.5 million in 2018 compared to 2017 due to higher oil and natural gas production from the Underlying Properties, where oil production increased 29% and natural gas production increased 57% in 2018 compared to 2017. There is a certain amount of variable lease operating expenses associated with the production from the Underlying Properties.

- Production, ad valorem and other taxes increased $2.0 million in 2018 compared to 2017 primarily due to the increase in production volumes. As a percentage of revenues, production, ad valorem and other taxes increased to 8.1% for the year ended December 31, 2018 compared to 7.2% for the year ended December 31, 2017.

- Development expenses decreased $0.2 million (5%) in 2018 compared to 2017 as a result of reduced capital development projects. Development expenses during the year ended December 31, 2018, included costs related to multiple workovers and the initial costs for drilling three new wells in the Permian Area. Development expenses during the year ended December 31, 2017 included costs related to six gross (0.5 net) wells in North Louisiana commenced drilling and the Haynesville drilling program in North Louisiana.

In September 2017, Enduro completed the sale of certain properties in the Permian Basin and, in connection with the sale, the Trust released its 80% Net Profits Interest in the properties in exchange for 80% of the net proceeds of the sales. The net proceeds of the sales were paid to Trust unitholders in a special distribution in October 2017. During the first quarter of 2018, $35,283 in general and administrative expenses incurred and paid by Enduro that were not initially charged to the Trust as part of the special distribution were deducted in calculating the net profits attributable to the Underlying Properties. Further, during the second quarter of 2018, $52,960 was deducted from the net profits attributable to the Underlying Properties due to the inclusion in prior period distribution calculations of certain expenses and revenues that related to properties sold as part of these divestitures. This resulted in total adjustments to the net profits attributable to the Underlying Properties for 2018 of $88,243.

The Trust withheld $0.5 million and paid $1.1 million for general and administrative expenses during the year ended December 31, 2018. Expenses paid during the period primarily consisted of fees for the preparation of 2017 tax information for unitholders, preparation of the Trust’s 2017 reserve report and Annual Report on Form 10-K, 2017 and 2018 financial statement audit fees, preparation of the Trust’s 2018 monthly press releases and Quarterly Reports on Form 10-Q, Trustee fees, and New York Stock Exchange listing fees. For the year ended December 31, 2017, the Trust withheld $0.9 million and paid $0.7 million for general and administrative expenses.

Years Ended December 31, 2017 and 2016

Income from Net Profits Interest for the year ended December 31, 2017 is calculated from the following:

- oil sales related to oil produced from the Underlying Properties primarily from September 2016 through June 2017;
- natural gas sales related to natural gas produced from the Underlying Properties primarily from August 2016 through May 2017; and
- direct operating and development expenses related to expenses and capital incurred primarily from October 2016 to July 2017.

Net profits attributable to the Underlying Properties for the year ended December 31, 2017 were $9.4 million compared to $11.6 million for the year ended December 31, 2016. As a result of direct operating expenses and development expenses exceeding oil and natural gas sales for the last two months of 2017, the Trust did not pay a distribution to unitholders for the last two months of 2017. Under the modified cash basis of accounting, as there was no distribution, the oil and natural gas sales, direct operating expenses and development expenses for such periods are not included in the table above or this analysis of net profits attributable to the Underlying Properties for the year ended December 31, 2017 versus the year ended December 31, 2016. Therefore, several variances between years are due to the year ended December 31, 2017 including ten months of results compared to twelve months for the year ended December 31, 2017. The $2.2 million decrease from 2016 to 2017 was primarily due to the following items:

- Oil sales decreased $1.8 million, primarily due to lower sales volumes, which decreased oil sales by $6.7 million. The offsetting $4.9 million increase in oil sales was due to higher realized prices. The average oil price received increased 21% as a result of the corresponding increase in the average NYMEX oil price for the relevant production months. Oil sales volumes decreased 22% primarily due to the year ended December 31, 2017 including only ten months of oil sales volumes. Offsetting the declines were volume increases in the Permian Basin relating to multiple months of production from two wells for which previously delayed payments were made during the second quarter of 2017. Although these two wells reached payout in mid-2013, the operator had not been paying Enduro for production from the wells. Oil cash receipts for these wells during the year ended 2017 that related to prior periods totaled $0.8 million, representing over four years of revenues, and oil volumes of approximately 12,000 Bbls. Excluding the accumulated receipts for these wells received in the second quarter of 2018, oil cash receipts and volumes would have been $28.0 million and approximately 609,900 Bbls, respectively, for the year ended December 31, 2017.

- Natural gas sales decreased $0.5 million due to lower sales volumes, which had a $2.7 million negative impact on natural gas sales. The decrease in realized sales volumes is offset by higher realized prices, which had a $2.2 million impact on natural gas sales. The average natural gas price received increased 34% as a result of the corresponding increases in the average NYMEX gas price for the relevant production months. Natural gas volumes decreased 29% primarily due to the year ended December 31, 2017 including only ten months of natural gas sales volumes. In addition, payment timing differences and natural production declines in the Elm Grove field of the East Texas / North Louisiana region accounted for 489,400 Mcf, or 37%, of the decline in natural gas volumes. Additionally, natural gas sales volumes in the year ended December 31, 2017 were lower due to the recoupment of previously paid volumes as described in Note 10 of the Notes to Financial Statements. The recoupment period began in the second quarter of 2016 and reduced volumes by approximately 65,500 Mcf more in the year ended December 31, 2017 as compared to the year ended December 31, 2016.

- CGT expenses decreased from $3.2 million in 2016 to $2.0 million in 2017. The decrease in CGT expenses is primarily attributable to a difference in the number of months included in the respective periods. In addition, in 2016, CGT expenses were higher than usual due to unused firm capacity reservation fees that were retroactively charged by an operator in the Elm Grove field of North Louisiana for several years beginning with the January 2012 production month. The retroactively charged firm capacity reservation fees included in CGT expenses for the year ended December 31, 2016 totaled $0.3 million.

- Lease operating expenses decreased $2.8 million primarily due to the two months of expenses not included in the 2017 period.

- Production, ad valorem and other taxes decreased $0.2 million primarily due to a $2.3 million decrease in total sales revenues. As a percentage of revenues, production, ad valorem and other taxes remained relatively consistent, with 2017 at 7.2% compared to 7.4% for the year ended December 31, 2016.

- Development expenses increased $4.2 million as a result of increased capital projects in the Permian Basin as well as capital development projects in the Elm Grove field of North Louisiana. During the year ended December 31, 2017, six gross (0.5 net) wells in North Louisiana commenced drilling, which increased capital expenditures by $2.0 million. The increased capital expenditures related to the Haynesville drilling program in North Louisiana caused expenses to exceed revenues for the last two months of 2017, resulting in a negative net profits interest for the respective periods. During the year ended December 31, 2016, the low commodity price environment led to a lack of capital projects and capital adjustments were recorded that resulted from projects where actual costs incurred were less than projected. Those adjustments more than offset capital expenditures incurred and increased net profits by $0.3 million.

During the year ended December 31, 2016, Enduro established a total reserve of $850,000 for approved 2016 development expenses and released $750,000 during the year as discussed in Note 8 of the Notes to Financial Statements in Item 8 of this Form 10-K. At December 31, 2016, $100,000 remained in the reserve for approved capital expenditures. In the distribution paid in January 2017, Enduro released the final $100,000 reserve and Enduro no longer maintained any reserve for development expenses

The Trust withheld $0.9 million and paid $0.7 million for general and administrative expenses during the year ended December 31, 2017. Expenses paid during the period primarily consisted of fees for the preparation of 2016 tax information for unitholders, preparation of the Trust’s 2016 reserve report and Annual Report on Form 10-K, 2016 and 2017 financial statement audit fees, preparation of the Trust’s 2017 monthly press releases and Quarterly Reports on Form 10-Q, Trustee fees, and New York Stock Exchange listing fees. For the year ended December 31, 2016, the Trust withheld $0.7 million and paid $0.7 million for general and administrative expenses.

Liquidity and Capital Resources

The Trust's principal sources of liquidity are cash flow generated from the Net Profits Interest and borrowing capacity under the letter of credit described below. Other than Trust administrative expenses, including any reserves established by the Trustee for future liabilities, the Trust's only use of cash is for distributions to Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Net Profits Interest and other sources (such as interest earned on any amounts reserved by the Trustee) in any given month, over the Trust's expenses paid for that month. Available funds are reduced by any cash the Trustee determines to hold as a reserve against future expenses.

The Trustee may create a cash reserve to pay for future liabilities of the Trust. If the Trustee determines that the cash on hand and the cash to be received are, or will be, insufficient to cover the Trust's liabilities, the Trustee may authorize the Trust to borrow money to pay administrative or incidental expenses of the Trust that exceed cash held by the Trust. The Trustee may authorize the Trust to borrow from any person, including the Trustee or the Delaware Trustee or an affiliate thereof, although none of the Trustee, the Delaware Trustee or any affiliate thereof intends to lend funds to the Trust. The Trustee may also cause the Trust to mortgage its assets to secure payment of the indebtedness. The terms of such indebtedness and security interest, if funds were to be loaned by the entity serving as Trustee or Delaware Trustee or an affiliate thereof, would be similar to the terms which such entity would grant to a similarly situated commercial customer with whom it did not have a fiduciary relationship. In addition, the Sponsor has provided the Trust with a $1.2 million letter of credit to be used by the Trust if its cash on hand (including available cash reserves) is insufficient to pay ordinary course administrative expenses. Further, if the Trust requires more than the $1.2 million under the letter of credit to pay administrative expenses, the Sponsor has agreed to loan funds to the Trust necessary to pay such expenses. Any loan made by the Sponsor to the Trust would be evidenced by a written promissory note, be on an unsecured basis, and have terms that are no less favorable to the Sponsor than those that would be obtained in an arm's length transaction between the Sponsor and an unaffiliated third party. If the Trust borrows funds or draws on the letter of credit, no further distributions will be made to Trust unitholders until such amounts borrowed or drawn are repaid. Except for the foregoing, the Trust has no source of liquidity or capital resources. The Trustee has no current plans to authorize the Trust to borrow money. At December 31, 2018 and 2017, the Trust held cash reserves of $827,169 and $366,773, respectively, for future Trust expenses. Since its formation, the Trust has not borrowed any funds and no amounts have been drawn on the letter of credit.

In February 2016, Enduro established a $750,000 reserve from that month's net profits interest calculation for approved 2016 development expenses. The Trust, in its discretion, also withheld $250,000 for anticipated future liabilities of the Trust. In March 2016, Enduro withheld an additional $100,000 to increase the previously established reserve for approved development expenses, a total reserve of $850,000. As a result of lower than anticipated expenditures during the year, over the course of the remaining 2016 distributions Enduro released $750,000 of the established reserve, thereby increasing the net profits attributable to the Trust. In the distribution paid in January 2017, Enduro released the final $100,000 reserve. COERT currently does not maintain any reserve for development expenses.

Cash held by the Trustee as a reserve against future liabilities or for distribution at the next distribution date may be held in a noninterest-bearing account or may be invested in:

- interest-bearing obligations of the United States government;
- money market funds that invest only in United States government securities;
- repurchase agreements secured by interest-bearing obligations of the United States government; or
- bank certificates of deposit.

Prior to the expiration of the hedge contracts in 2014, the amounts received by Enduro from hedge contract counterparties upon settlement of the hedge contracts reduced the operating expenses related to the Underlying Properties in calculating income from the Net Profits Interest in the first and second quarters of 2014. Neither Enduro nor COERT have entered into any hedge contracts relating to oil and natural gas volumes expected to be produced after 2013 and the terms of the Conveyance prohibit COERT from entering into new hedging arrangements burdening the Trust.

The Trust pays the Trustee an administrative fee of $200,000 per year. The Trust pays the Delaware Trustee an annual fee of $2,000. The Trust also incurs, either directly or as a reimbursement to the Trustee, legal, accounting, tax and engineering fees, printing costs and other expenses that are deducted by the Trust before distributions are made to Trust unitholders. The Trust also is responsible for paying other expenses incurred as a result of being a publicly traded entity, including costs associated with annual and quarterly reports to Trust unitholders, tax return and Form 1099 preparation and distribution, NYSE listing fees, independent auditor fees and registrar and transfer agent fees.

The Trust does not have any transactions, arrangements or other relationships with unconsolidated entities or persons that could materially affect the Trust's liquidity or the availability of capital resources.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements. The Trust has not guaranteed the debt of any other party, nor does the Trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations.

New Accounting Pronouncements

As the Trust's financial statements are prepared on the modified cash basis, most accounting pronouncements are not applicable to the Trust's financial statements. No new accounting pronouncements have been adopted or issued that would impact the financial statements of the Trust.

Critical Accounting Policies and Estimates

The Trust uses the modified cash basis of accounting to report Trust receipts of income from the Net Profits Interest and payments of expenses incurred. The Net Profits Interest represents the right to receive revenues (oil and natural gas sales), less direct operating expenses (lease operating expenses and production and property taxes) and development expenses of the Underlying Properties plus any payments made or net payments received in connection with the settlement of certain hedge contracts, multiplied by 80%. Cash distributions of the Trust are made based on the amount of cash received by the Trust pursuant to terms of the conveyance creating the Net Profits Interest.

Under the terms of the Conveyance, the monthly Net Profits Interest calculation includes oil and natural gas revenues received. Monthly operating expenses and capital expenditures represent incurred expenses, and as a result, represent accrued expenses as well as expenses paid during the period.

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

(a) Income from Net Profits Interest is recorded when distributions are received by the Trust;

(b) Distributions to Trust unitholders are recorded when paid by the Trust;

(c) Trust general and administrative expenses (which includes the Trustee's fees as well as accounting, engineering, legal, and other professional fees) are recorded when paid;

(d) Cash reserves for Trust expenses may be established by the Trustee for certain future expenditures that would not be recorded as contingent liabilities under accounting principles generally accepted in the United States of America ("GAAP");

(e) Amortization of the Net Profits Interest in oil and natural gas properties is calculated on a unit-of-production basis and is charged directly to the Trust corpus. Such amortization does not affect cash earnings of the Trust; and

(f) The Net Profits Interest in oil and natural gas properties is periodically assessed whenever events or circumstances indicate that the aggregate value may have been impaired below its total capitalized cost based on the Underlying Properties. If an impairment loss is indicated by the carrying amount of the assets exceeding the sum of the undiscounted expected future net cash flows of the Net Profits Interest, then an impairment loss is recognized for the amount by which the carrying amount of the asset exceeds its estimated fair value determined using discounted cash flows.

The financial statements of the Trust differ from financial statements prepared in accordance with GAAP because revenues are not accrued in the month of production; certain cash reserves may be established for contingencies which would not be accrued in financial statements prepared in accordance with GAAP; general and administrative expenses are recorded when paid instead of when incurred; and amortization of the net profits interest calculated on a unit-of-production basis is charged directly to trust corpus instead of as an expense. While these statements differ from financial statements prepared in accordance with GAAP, the modified cash basis of reporting revenues, expenses, and distributions is considered to be the most meaningful because monthly distributions to the Trust unitholders are based on net cash receipts.

This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the SEC as specified by Staff Accounting Bulletin Topic 12:E, *Financial Statements of Royalty Trusts*.

The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Oil and Natural Gas Reserves. The proved oil and natural gas reserves for the Underlying Properties are estimated by independent petroleum engineers. Reserve engineering is a subjective process that is dependent upon the quality of available data and the interpretation thereof. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors such as changes in product prices, may justify revision of such estimates. Because proved reserves are required to be estimated using prices at the date of the evaluation, estimated reserve quantities can be significantly impacted by changes in product prices. Accordingly, oil and natural gas quantities ultimately recovered and the timing of production may be substantially different from original estimates.

The Financial Accounting Standards Board requires supplemental disclosures for oil and gas producers based on a standardized measure of discounted future net cash flows relating to proved oil and natural gas reserve quantities. Under this disclosure, future cash inflows are computed by applying the average prices during the 12-month period prior to fiscal year-end, determined as an unweighted arithmetic average of the first-day-of-the-month benchmark price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Future price changes are only considered to the extent provided by contractual arrangements in existence at year-end. The standardized measure of discounted future net cash flows is achieved by using a discount rate of 10% a year to reflect the timing of future cash flows relating to proved oil and natural gas reserves. Changes in any of these assumptions, including consideration of other factors, could have a significant impact on the standardized measure. The standardized measure does not necessarily result in an estimate of the current fair market value of proved reserves.

Amortization of Net Profits Interest. The Trust calculates amortization of the Net Profits Interest in oil and natural gas properties on a unit-of-production basis based on the Underlying Properties' production and reserves. The reserves upon which the amortization rate is based are quantity estimates which are subject to numerous uncertainties inherent in the estimation of proved reserves. The volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. These estimates are expected to change as additional information becomes available in the future. Downward revisions in proved reserves may result in an increased rate of amortization. Amortization is recorded on sales volumes paid by the Trust during the relevant period and is charged directly to the Trust corpus balance. As a result, amortization does not affect the cash earnings of the Trust.

Impairment of Net Profits Interest. The Net Profits Interest in oil and natural gas properties is periodically assessed for impairment whenever events or circumstances indicate that the current fair value based on expected future cash flows of the Underlying Properties may be less than the carrying value of the

Net Profits Interest. The Trust did not realize any impairment during the years ended December 31, 2018, 2017 or 2016. Future downward revisions in actual production volumes relative to current forecasts, higher than expected operating costs, or lower than anticipated market pricing could result in recognition of impairment in future periods. Any impairment of the Net Profits Interest will result in a non-cash charge to Trust corpus and will not affect distributable income. For further information, see “Note 5. Fair Value Measurements” of the Notes to Financial Statements in Item 8 of this Form 10-K.

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

As a "smaller reporting company" as defined in Item 10(f)(1) of Regulation S-K, the Trust is not required to provide information required by this Item.

Item 8. ***Financial Statements and Supplementary Data.***

Report of Independent Registered Public Accounting Firm

To the Trustee and Unitholders of Permianville Royalty Trust

Opinion on the Financial Statements

We have audited the accompanying statements of assets, liabilities, and trust corpus of Permianville Royalty Trust (the Trust) as of December 31, 2018 and 2017, the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Trust at December 31, 2018 and 2017, and its distributable income for each of the three years in the period ended December 31, 2018, in conformity with the modified cash basis of accounting, as described in Note 2, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Trust's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework), and our report dated March 18, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on the Trust's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by the Trustee, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Trust's auditor since 2011.

Fort Worth, Texas
March 18, 2019

PERMIANVILLE ROYALTY TRUST

Statements of Assets, Liabilities and Trust Corpus

	December 31, 2018	December 31, 2017
ASSETS		
Cash and cash equivalents	$ 827,169	$ 366,773
Net profits interest in oil and natural gas properties, net	83,257,020	93,733,160
Total assets	$ 84,084,189	$ 94,099,933
LIABILITIES AND TRUST CORPUS		
Trust corpus (33,000,000 units issued and outstanding)	$ 84,084,189	$ 94,099,933
Total liabilities and Trust corpus	$ 84,084,189	$ 94,099,933

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

PERMIANVILLE ROYALTY TRUST

Statements of Distributable Income

	Year Ended December 31,		
	2018	2017	2016
Income from net profits interest	$ 15,186,781	$ 7,643,960	$ 9,216,320
Income from sale of net profits interest on undeveloped acreage	751,732	36,300,165	—
Income from sale of net profits interest on producing properties	—	1,650,000	—
Interest and investment income	9,583	15,328	572
General and administrative expenses	(1,132,964)	(682,938)	(654,132)
Cash reserves withheld for Trust expenses	(460,396)	(182,442)	(76,480)
Distributable income	$ 14,354,736	$ 44,744,073	$ 8,486,280
Distributable income per unit (33,000,000 units)	$ 0.434992	$ 1.355881	$ 0.257160

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

PERMIANVILLE ROYALTY TRUST

Statements of Changes in Trust Corpus

	Year Ended December 31, 2018	2017	2016
Trust corpus, beginning of period	$ 94,099,933	$ 107,324,542	$ 121,009,502
Sale of net profits interest on producing properties	—	(1,650,000)	—
Cash reserves withheld (used) for Trust expenses	460,396	182,442	76,480
Distributable income	14,354,736	44,744,073	8,486,280
Distributions to unitholders	(14,354,736)	(44,744,073)	(8,486,280)
Amortization of net profits interest	(10,476,140)	(11,757,051)	(13,761,440)
Trust corpus, end of year	$ 84,084,189	$ 94,099,933	$ 107,324,542

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

PERMIANVILLE ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS

1. TRUST ORGANIZATION AND PROVISIONS

Permianville Royalty Trust (the “Trust”), previously known as Enduro Royalty Trust, is a Delaware statutory trust formed in May 2011 pursuant to a trust agreement (the “Trust Agreement”) among Enduro Resource Partners LLC (“Enduro”), as trustor, The Bank of New York Mellon Trust Company, N.A. (the “Trustee”), as trustee, and Wilmington Trust Company (the “Delaware Trustee”), as Delaware Trustee.

The Trust was created to acquire and hold for the benefit of the Trust unitholders a net profits interest representing the right to receive 80% of the net profits from the sale of oil and natural gas production from certain properties in the states of Texas, Louisiana and New Mexico held by Enduro as of the date of the conveyance of the net profits interest to the Trust (the “Net Profits Interest”). The properties in which the Trust holds the Net Profits Interest are referred to as the “Underlying Properties.”

In connection with the closing of the initial public offering in November 2011, Enduro contributed the Net Profits Interest to the Trust in exchange for 33,000,000 units of beneficial interest in the Trust (the “Trust Units”). Through the initial public offering in 2011 and a secondary offering in 2013, Enduro sold a total of 24,400,000 Trust Units. As of December 31, 2017, Enduro owned 8,600,000 Trust Units, or 26% of the issued and outstanding Trust Units.

At a special meeting of Trust unitholders held on August 30, 2017, unitholders approved several proposals, including amendments to the Trust Agreement. In September 2017, Enduro, the Trustee and the Delaware Trustee entered into the First Amendment to Amended and Restated Trust Agreement, which amended certain provisions of the Trust Agreement to, among other things, allow Enduro to sell interests in the Underlying Properties free and clear of the Net Profits Interest with the approval of Trust unitholders holding at least 50% of the then outstanding units of the Trust at a meeting held in accordance with the requirements of the Trust Agreement. This amendment reduced the required threshold for approval of such sales from 75% to 50% of the outstanding units of the Trust.

In July 2018 Enduro entered into a purchase and sale agreement with COERT Holdings 1 LLC (“COERT” or the “Sponsor”) for the Underlying Properties and all of the outstanding Trust Units owned by Enduro (the “Sale Transaction”), and on August 31, 2018, the parties closed the Sale Transaction. In connection with the Sale Transaction, COERT assumed all of Enduro’s obligations under the Trust Agreement and other instruments to which Enduro and the Trustee were parties. As of December 31, 2018, the Sponsor owned 8,600,000 Trust Units, or 26% of the issued and outstanding Trust Units.

The Net Profits Interest is passive in nature and neither the Trust nor the Trustee has any management control over or responsibility for costs relating to the operation of the Underlying Properties. The Trust Agreement provides, among other provisions, that:

- the Trust’s business activities are limited to owning the Net Profits Interest and any activity reasonably related to such ownership, including activities required or permitted by the terms of the Conveyance of Net Profits Interest, dated effective as of July 1, 2011 (as supplemented and amended to date, the “Conveyance”). As a result, the Trust is not permitted to acquire other oil and natural gas properties or net profits interests or otherwise to engage in activities beyond those necessary for the conservation and protection of the Net Profits Interest;
- the Trust may dispose of all or any material part of the assets of the Trust (including the sale of the Net Profits Interests) if approved by at least 75% of the outstanding Trust Units;
- the Sponsor may sell a divided or undivided portion of its interests in the Underlying Properties, free from and unburdened by the Net Profits Interest, if approved by at least 50% of the outstanding Trust Units at a meeting of Trust unitholders;
- the Trustee will make monthly cash distributions to unitholders (Note 7);
- the Trustee may create a cash reserve to pay for future liabilities of the Trust;
- the Trustee may authorize the Trust to borrow money to pay administrative or incidental expenses of the Trust that exceed its cash on hand and available reserves. No further distributions will be made to Trust unitholders until such amounts borrowed are repaid; and
- the Trust is not subject to any pre-set termination provisions based on a maximum volume of oil or natural gas to be produced or the passage of time. The Trust will dissolve upon the earliest to occur of the following:
  - the Trust, upon approval of the holders of at least 75% of the outstanding Trust Units, sells the Net Profits Interest;
  - the annual cash proceeds received by the Trust attributable to the Net Profits Interest are less than $2 million for each of any two consecutive years;
  - the holders of at least 75% of the outstanding Trust Units vote in favor of dissolution; or
  - the Trust is judicially dissolved.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

The Trust uses the modified cash basis of accounting to report Trust receipts of income from the Net Profits Interest and payments of expenses incurred. The Net Profits Interest represents the right to receive revenues (oil and natural gas sales), less direct operating expenses (including lease operating expenses and production and property taxes) and development expenses of the Underlying Properties, multiplied by 80%. Cash distributions of the Trust are made based on the amount of cash received by the Trust from the Sponsor pursuant to terms of the Conveyance creating the Net Profits Interest.

Under the terms of the Conveyance, the monthly Net Profits Interest calculation includes oil and natural gas revenues received by the Sponsor during the relevant month. Monthly operating expenses and capital expenditures represent estimated incurred expenses, and as a result, represent accrued expenses as well as expenses paid during the period.

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

(a) Income from Net Profits Interest is recorded when distributions are received by the Trust;

(b) Distributions to Trust unitholders are recorded when paid by the Trust;

(c) Trust general and administrative expenses (which includes the Trustee's fees as well as accounting, engineering, legal, and other professional fees) are recorded when paid;

(d) Cash reserves for Trust expenses may be established by the Trustee for certain future expenditures that would not be recorded as contingent liabilities under accounting principles generally accepted in the United States of America ("GAAP");

(e) Amortization of the Net Profits Interest in oil and natural gas properties is calculated on a unit-of-production basis and is charged directly to the Trust corpus; and

(f) The Net Profits Interest in oil and natural gas properties is periodically assessed whenever events or circumstances indicate that the aggregate value may have been impaired below its total capitalized cost based on the Underlying Properties. If an impairment loss is indicated by the carrying amount of the assets exceeding the sum of the undiscounted expected future net cash flows of the Net Profits Interest, then an impairment loss is recognized for the amount by which the carrying amount of the asset exceeds its estimated fair value determined using discounted cash flows.

The financial statements of the Trust differ from financial statements prepared in accordance with GAAP because revenues are not accrued in the month of production; certain cash reserves may be established for contingencies which would not be accrued in financial statements prepared in accordance with GAAP; general and administrative expenses are recorded when paid instead of when incurred; and amortization of the net profits interest calculated on a unit-of-production basis is charged directly to trust corpus instead of as an expense. While these statements differ from financial statements prepared in accordance with GAAP, the modified cash basis of reporting revenues, expenses, and distributions is considered to be the most meaningful because monthly distributions to the Trust unitholders are based on net cash receipts.

This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission ("SEC") as specified by Staff Accounting Bulletin Topic 12:E, *Financial Statements of Royalty Trusts*.

Use of Estimates

The preparation of financial statements in conformity with the basis of accounting described above requires the Trust to make estimates and assumptions that affect reported amounts of assets and liabilities and the reported amounts of revenues and expenses during the reporting period. Significant estimates affecting these financial statements include estimates of proved oil and natural gas reserves, which are used to compute the Trust's amortization of net profits interest and its impairment assessments. Although the Trustee believes that these estimates are reasonable, actual results could differ from those estimates.

Cash and Cash Equivalents

Cash and cash equivalents include cash in banks, money market accounts, and all highly liquid investments with an original maturity of three months or less.

Impairment

The Net Profits Interest in oil and natural gas properties is periodically assessed for impairment whenever events or circumstances indicate that the current fair value based on expected future cash flows of the Underlying Properties may be less than the carrying value of the Net Profits Interest. While the Trust did not record an impairment during the years ended December 31, 2018, 2017 or 2016, future downward revisions in actual production volumes relative to current forecasts, higher than expected operating costs, or lower than anticipated commodity prices could result in recognition of impairment in future periods.

New Accounting Pronouncements

As the Trust's financial statements are prepared on the modified cash basis, most accounting pronouncements are not applicable to the Trust's financial statements. No new accounting pronouncements have been adopted or issued that would impact the financial statements of the Trust.

3. NET PROFITS INTEREST IN OIL AND NATURAL GAS PROPERTIES

The Net Profits Interest in oil and natural gas properties was recorded at its fair value on the date of conveyance. Amortization of the Net Profits Interest in oil and natural gas properties is calculated on a unit-of-production basis based on the Underlying Properties' production and reserves. As the Trust uses the modified cash basis of accounting, amortization is recognized only in those months for which income from net profits interest exceeds capital expenditures. The reserves upon which the amortization rate is based are quantity estimates which are subject to numerous uncertainties inherent in the estimation of proved reserves. The volumes considered to be commercially recoverable fluctuate with changes in commodity prices and operating costs. These estimates are expected to change as additional information becomes available in the future. Downward revisions in proved reserves may result in an increased rate of amortization. Amortization is charged directly to the Trust corpus balance and does not affect the distributable income of the Trust. Accumulated amortization as of December 31, 2018 and 2017 was $273,834,138 and $263,357,998, respectively.

The Net Profits Interest is periodically assessed for impairment whenever events or circumstances indicate that the current fair value based on expected future cash flows of the Underlying Properties may be less than the carrying value of the Net Profits Interest. While the Trust did not record an impairment during the years ended December 31, 2018, 2017 or 2016, future downward revisions in actual production volumes relative to current forecasts, higher than expected operating costs, or lower than anticipated commodity prices could result in recognition of impairment in future periods. For further information, see "Note 5. Fair Value Measurements."

As further discussed in "Note 4. Divestiture of Net Profits Interest in Certain Permian Basin Properties," in September 2017, Enduro completed the sale of certain properties in the Permian Basin and, in connection with the sale, the Trust released its 80% Net Profits Interest in the properties in exchange for 80% of the net proceeds of the sales. As a result of the divestiture, and concurrent with the distribution of cash to the Trust that occurred in October 2017, the Trust reduced the carrying value of the Net Profits Interest reflected on the accompanying Statement of Assets, Liabilities and Trust Corpus by $1,650,000, which was the portion of the net sales proceeds allocated to producing properties. The remainder of the net sales proceeds, totaling $36,300,165, was attributed to the sale of the net profits interest on undeveloped acreage and not reflected in the carrying value of the Net Profits Interest. See "Note 5. Fair Value Measurements" for further discussion of the fair value of the divested properties, which was the basis for allocating net proceeds between producing properties and undeveloped acreage.

4. DIVESTITURE OF NET PROFITS INTEREST IN CERTAIN PERMIAN BASIN PROPERTIES

In June 2017, Enduro notified the Trustee that Enduro had entered into eight separate purchase and sale agreements to divest certain acreage and associated production in the Permian Basin (the "Divestiture Properties") that constituted part of the Underlying Properties and were therefore burdened by the Trust's Net Profits Interest. On August 30, 2017, at a special meeting of Trust unitholders, the unitholders approved (i) the eight transactions pursuant to which Enduro would sell the Divestiture Properties, (ii) the release of the Trust's 80% Net Profits Interest in the Divestiture Properties, and (iii) the related proposals to effect the sale transactions in exchange for the Trust receiving 80% of the net proceeds from the sale of the Divestiture Properties.

In September 2017, Enduro, the Trustee and the Delaware Trustee entered into the First Amendment to Amended and Restated Trust Agreement, which amended certain provisions of the Trust Agreement to, among other things, allow Enduro to sell interests in the Underlying Properties free and clear of the Net Profits Interest with the approval of Trust unitholders holding at least 50% of the then outstanding units of the Trust at a meeting held in accordance with the requirements of the Trust Agreement. This amendment reduced the required threshold for approval of such sales from 75% to 50% of the outstanding units of the Trust. To effect the same changes as those included in the amended Trust Agreement, Enduro, the Trustee and the Delaware Trustee also entered into the First Amendment to Conveyance of Net Profits Interest. As a result of the Trust unitholders approving amendments to the Trust Agreement and Conveyance and the approval of the divestiture of the Divestiture Properties, Enduro and the Trustee entered into the Partial Release, Reconveyance and Termination Agreement (the "Partial Release"). Pursuant to the terms of the Partial Release, the Trustee, on behalf of the Trust, reconveyed, terminated and released to Enduro the Net Profits Interest with respect to the Divestiture Properties sold pursuant to eight letter agreements or purchase and sale agreements, as applicable, entered into between Enduro and eight separate counterparties.

In September 2017, Enduro completed the sale of the Divestiture Properties. The following table displays the aggregate net proceeds from the sale of the Divestiture Properties and the aggregate net proceeds allocable to Trust unitholders:

Proceeds to Enduro from sale of Divestiture Properties	$ 49,141,943
Less: Transaction expenses	(766,737)
Net proceeds from sale of Divestiture Properties	48,375,206
Percentage allocable to Trust's Net Profits Interest	80%
Net proceeds allocable to the Trust	38,700,165
Indemnity holdback	(750,000)
Cash distributed to Trust unitholders from divestiture of Net Profits Interest	$ 37,950,165
Number of Trust Units	33,000,000
Special distribution per Trust Unit	$ 1.150005

Total proceeds received by Enduro from the sale of the Divestiture Properties, after preliminary closing adjustments, were approximately $49.1 million. After deducting transaction expenses of $766,737, net proceeds to Enduro were $48.4 million, of which the proceeds allocable to the Trust were $38.7 million in accordance with its 80% Net Profits Interest. As a result of these transactions, a special distribution of $1.150005 per unit was paid on October 20, 2017 to Trust unitholders. Pursuant to an agreement between Enduro and the Trust, Enduro withheld $750,000 (the "Holdback Amount") of the net proceeds allocable to the Trust to cover possible indemnification obligations under the purchase and sale agreements within 25 months of the closing of the transactions, or by the end of October 2019 (the "Indemnification Period"). In connection with the Sale Transaction, Enduro released the Holdback Amount to the Trustee on September 4, 2018. The Trustee intends to retain the Holdback Amount for the remainder of the Indemnification Term, which will end in October 2019. The Trustee may elect to continue to retain all or a portion of the Holdback Amount beyond the expiration of the Indemnification Term as a cash reserve for future liabilities of the Trust.

As discussed in "Note 5. Fair Value Measurements," the cash distributed to Trust unitholders as a result of the divestitures of the Net Profits Interest was allocated between producing properties and undeveloped acreage based on the fair value of the Divestiture Properties. The $1,650,000 allocated to producing properties reduced the carrying value of the “Net profits interest in oil and natural gas properties, net” line item on the Statement of Assets, Liabilities and Trust Corpus at December 31, 2017 and is shown as “Income from sale of net profits interest on producing properties” on the Statement of Distributable Income for the year ended December 31, 2017. The remaining amount was allocated to undeveloped acreage and is reflected in the Statement of Distributable Income as “Income from sale of net profits interest on undeveloped acreage.” As the proceeds received from the sale of the Divestiture Properties were primarily attributable to undeveloped acreage, the net profits generated from the Divestiture Properties have been insignificant to the Trust historically.

5. FAIR VALUE MEASUREMENTS

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The three approaches for measuring the fair value of assets and liabilities are the market approach, the income approach and the cost approach, each of which includes multiple valuation techniques. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. The income approach uses valuation techniques to measure fair value by converting future amounts, such as cash flows or earnings, into a single present value amount using current market expectations about those future amounts. The cost approach is based on the amount that would currently be required to replace the service capacity of an asset, often referred to as current replacement cost. The cost approach assumes that the fair value would not exceed what it would cost a market participant to acquire or construct a substitute asset of comparable utility, adjusted for obsolescence.

The fair value accounting standards do not prescribe which valuation technique should be used when measuring fair value and do not prioritize among the techniques. These standards establish a fair value hierarchy that prioritizes the inputs used in applying the various valuation techniques. Inputs broadly refer to the assumptions that market participants use to make pricing decisions, including assumptions about risk. Level 1 inputs are given the highest priority in the fair value hierarchy, while Level 3 inputs are given the lowest priority. The three levels of the fair value hierarchy are as follows:

- Level 1 — Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

- Level 2 — Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

- Level 3 — Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management’s best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

Fair Values—Non-recurring

Divestiture of Net Profits Interest

In connection with the divestiture of the Net Profits Interest as discussed in Note 4, the fair value of the producing properties sold in relation to the fair value of the Underlying Properties was evaluated utilizing an undiscounted cash flow model as of the date of sale. This fair value measurement using an income approach was based upon internal estimates of future production levels, prices, drilling and operating costs and discount rates, which are Level 3 inputs. Internal price estimates were developed based on third-party longer-term commodity futures price outlooks. Based on this analysis, the expected future net cash flows of the producing properties sold discounted at an annual rate of 10 percent was approximately $2.2 million, representing approximately 1.7% of the total expected future net cash flows of the Underlying Properties discounted at an annual rate of 10 percent.

As the producing properties sold by Enduro represented 1.7% of the fair value of the Underlying Properties, the Trust reduced the carrying value of the Net Profits Interest reflected on its financial statements by 1.7%, or approximately $1.7 million, in October 2017.

Impairment of Net Profits Interest

Although the Trust did not record an impairment during the years ended December 31, 2018, 2017 or 2016, it is reasonably possible that the estimates of undiscounted future net cash flows attributable to the Underlying Properties may change in the future resulting in the need to further impair the carrying value of the Net Profits Interest. The primary factors that may affect estimates of future cash flows include: revisions, both positive and negative, to estimates of oil and natural gas reserves; changes in estimated average realized oil and natural gas prices; and results of future drilling activities.

6. INCOME TAXES

Federal Income Taxes

For federal income tax purposes, the Trust is a grantor trust and therefore is not subject to tax at the trust level. Trust unitholders are treated as owning a direct interest in the assets of the Trust, and each Trust unitholder is taxed directly on his or her pro rata share of the income and gain attributable to the assets of the Trust and entitled to claim his or her pro rata share of the deductions and expenses attributable to the assets of the Trust. The income of the Trust is deemed to have been received or accrued by each unitholder at the time such income is received or accrued by the Trust rather than when distributed by the Trust.

The deductions of the Trust consist of severance taxes and administrative expenses. In addition, each unitholder is entitled to depletion deductions because the Net Profits Interest constitutes "economic interests" in oil and natural gas properties for federal income tax purposes. Each unitholder is entitled to amortize the cost of the Trust Units through cost depletion over the life of the Net Profits Interest or, if greater, through percentage depletion. Unlike cost depletion, percentage depletion is not limited to a unitholder's depletable tax basis in the Trust Units. Rather, a unitholder could be entitled to percentage depletion as long as the applicable Underlying Properties generate net income.

Some Trust Units are held by a middleman, as such term is broadly defined in U.S. Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust ("WHFIT") for U.S. federal income tax purposes. The Bank of New York Mellon Trust Company, N.A., 601 Travis, 16th Floor, Houston, Texas 77002, telephone number (512) 236-6545, is the representative of the Trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT. Tax information is also posted by the Trustee at www.permianvilleroyaltytrust.com. Notwithstanding the foregoing, the middlemen holding units on behalf of unitholders, and not the Trustee of the Trust, are solely responsible for complying with the information reporting requirements under the U.S. Treasury Regulations with respect to such units, including the issuance of IRS Forms 1099 and certain written tax statements. Unitholders whose units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the Trust Units.

The tax consequences to a unitholder of ownership of Trust Units will depend in part on the unitholder's tax circumstances. Unitholders should consult their tax advisors about the federal tax consequences relating to owning the Trust Units.

State Taxes

The Trust's revenues are from sources in the states of Louisiana, New Mexico and Texas. Because it distributes all of its net income to unitholders, the Trust is not taxed at the trust level in Louisiana or New Mexico. Although the Trust does not owe tax, the Trustee is required to file a return with Louisiana reflecting the income and deductions of the Trust attributable to properties located in that state. Louisiana and New Mexico presently have income taxes which tax income of nonresidents from real property located within that state. Louisiana and New Mexico also impose a corporate income tax which may apply to unitholders organized as corporations.

Texas imposes a franchise tax at a rate of 0.75% on gross revenues less certain deductions for returns originally due on or after January 1, 2016, as specifically set forth in the Texas franchise tax statutes. Entities subject to tax generally include trusts unless otherwise exempt. Trusts that receive at least 90% of their federal gross income from designated passive sources, including royalties from mineral properties and other income from other non-operating mineral interests, and do not receive more than 10% of their income from operating an active trade or business, generally are exempt from the Texas franchise tax as "passive entities." Although the Trust is intended to be exempt from Texas franchise tax at the trust level as a passive entity, each unitholder that is considered a taxable entity under the Texas franchise tax would generally be required to include its portion of Trust net income in its own Texas franchise tax computation.

Each unitholder should consult his or her own tax advisor regarding state tax requirements, if any, applicable to such person's ownership of Trust Units.

PERMIANVILLE ROYALTY TRUST
NOTES TO FINANCIAL STATEMENTS—Continued

7. DISTRIBUTIONS TO UNITHOLDERS

Each month, the Trustee determines the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust from the Net Profits Interest and other sources (such as interest earned on any amounts reserved by the Trustee) that month, over the Trust's liabilities for that month, subject to adjustments for changes made by the Trustee during the month in any cash reserves established for future liabilities of the Trust. Distributions are made to the holders of Trust Units as of the applicable record date (generally the last business day of each calendar month) and are payable on or before the 10th business day after the record date.

The following table provides information regarding the Trust's distributions paid during the periods indicated:

Declaration Date	Record Date	Payment Date	Distribution per Unit
2018:			
December 18, 2017	December 29, 2017	January 16, 2018	$ 0.016359
January 19, 2018	January 31, 2018	February 14, 2018	$ 0.018433
February 16, 2018	February 28, 2018	March 14, 2018	$ 0.037125
March 19, 2018	March 29, 2018	April 13, 2018	$ 0.040499
April 20, 2018	April 30, 2018	May 14, 2018	$ 0.059578
May 18, 2018	May 31, 2018	June 14, 2018	$ 0.034256
June 19, 2018	June 29, 2018	July 16, 2018	$ 0.058200
July 20, 2018	July 31, 2018	August 14, 2018	$ 0.043178
August 21, 2018	August 31, 2018	September 17, 2018	$ 0.043769
September 18, 2018	September 28, 2018	October 12, 2018	$ 0.038593
October 19, 2018	October 31, 2018	November 15, 2018	$ 0.007100
November 19, 2018	November 30, 2018	December 14, 2018	$ 0.037902
Total—2018			**$ 0.434992**
2017:			
December 19, 2016	December 30, 2016	January 17, 2017	$ 0.013980
January 20, 2017	January 31, 2017	February 14, 2017	$ 0.036205
February 17, 2017	February 28, 2017	March 14, 2017	$ 0.017331
March 21, 2017	March 31, 2017	April 14, 2017	$ 0.040901
April 18, 2017	April 28, 2017	May 12, 2017	$ 0.035220
May 19, 2017	May 31, 2017	June 14, 2017	$ 0.023001
June 20, 2017	June 30, 2017	July 17, 2017	$ 0.015040
July 21, 2017	July 31, 2017	August 14, 2017	$ 0.011227
August 21, 2017	August 31, 2017	September 15, 2017	$ 0.009327
September 19, 2017	September 29, 2017	October 16, 2017	$ 0.003644
September 25, 2017 – Special Distribution	October 5, 2017	October 20, 2017	$ 1.150005
Total—2017			**$ 1.355881**
2016:			
December 18, 2015	December 31, 2015	January 15, 2016	$ 0.029187
January 19, 2016	January 29, 2016	February 12, 2016	$ 0.029839
February 19, 2016	February 29, 2016	March 14, 2016	$ 0.024305
March 21, 2016	March 31, 2016	April 14, 2016	$ 0.009855
April 19, 2016	April 29, 2016	May 13, 2016	$ 0.007279
May 20, 2016	May 31, 2016	June 14, 2016	$ 0.001016
June 20, 2016	June 30, 2016	July 15, 2016	$ 0.013353
July 19, 2016	July 29, 2016	August 12, 2016	$ 0.015600
August 19, 2016	August 31, 2016	September 15, 2016	$ 0.029923
September 20, 2016	September 30, 2016	October 17, 2016	$ 0.036876
October 21, 2016	October 31, 2016	November 15, 2016	$ 0.031870
November 18, 2016	November 30, 2016	December 14, 2016	$ 0.028057
Total—2016			**$ 0.257160**

8. DEVELOPMENT EXPENSE RESERVE

During the first quarter of 2016, Enduro established a reserve of $750,000 from the calculated net profits interest for approved 2016 development expenses, which was held by Enduro. During the second quarter of 2016, Enduro increased the previously established reserve by $100,000, for a total of $850,000 withheld for approved 2016 development expenses. During the year ended December 31, 2016, no development expenses were applied against the reserve. However, as a result of lower than anticipated capital expenditures, Enduro released $750,000 of the reserve during the second half of 2016, which increased the income from net profits interest for that period. During the first three months of 2017, Enduro released the remaining $100,000 of the reserve. Prior to 2016, Enduro had not established a reserve for development expenses.

9. TRUSTEE FEES AND RELATED PARTY TRANSACTIONS

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee and $2,000 to the Delaware Trustee. During the year ended December 31, 2018, the Trust paid $202,018 to the Trustee and $2,010 to the Delaware Trustee pursuant to the terms of the Trust Agreement. During the years ended December 31, 2017 and 2016, the Trust paid $200,997 and $201,032, respectively, to the Trustee and $2,000 and $0, respectively, to the Delaware Trustee. The Delaware Trustee fee may be paid subsequent to period end; therefore, no fee is reflected for certain years.

Registration Rights Agreement. The Trust and COERT (as the assignee of Enduro, in connection with the Sale Transaction) are parties to a Registration Rights Agreement, as amended, whereby COERT, its affiliates and certain permitted transferees holding registrable Trust Units are entitled, upon receipt by the Trustee of written notice from holders of a majority of the then outstanding registrable Trust Units, to demand that the Trust effect the registration of the registrable Trust Units. The holders of the registrable Trust Units are entitled to demand a maximum of five such registrations. In connection with the preparation and filing of any registration statement, COERT will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust. Any underwriting discounts and commissions will be borne by the seller of the Trust Units.

10. PERMIAN BASIN OPERATOR ADJUSTMENT AND IMPACT ON FUTURE DISTRIBUTIONS

As previously disclosed, Enduro received a letter in July 2015 from one of its operators in the Permian Basin pertaining to 480,000 Mcf of natural gas for which the operator had paid Enduro on the Underlying Properties but for which Enduro had only produced 240,000 Mcf. Subsequently, the operator and Enduro agreed that the value of the overpaid production, totaling $1.1 million to the Underlying Properties, would be recouped with proceeds from future production.

During the recoupment period, which began during the second quarter of 2016, Enduro did not, and following the Sale Transaction, the Sponsor will not, receive any revenue payments, and future distribution calculations will not include any volumes or revenues from any of the operator’s properties until the $1.1 million is fully recovered. For the year ended December 31, 2018, these properties would have contributed approximately 2,100 Bbls, amounting to $0.1 million in oil receipts, and 130,500 Mcf, amounting to $0.5 million in natural gas receipts. After deducting $0.2 million in revenue deductions for taxes and transportation expenses, a total of $0.4 million has been withheld by the operator for the year ended December 31, 2018. For the year ended December 31, 2017, these properties would have contributed approximately 5,900 Bbls, amounting to $0.2 million in oil receipts, and 191,200 Mcf, amounting to $0.5 million in natural gas receipts. After deducting $0.3 million in revenue deductions for taxes and transportation expenses, a total of $0.5 million has been withheld by the operator for the year ended December 31, 2017. For the year ended December 31, 2016, the properties would have contributed approximately 4,200 Bbls, amounting to $0.2 million in oil receipts, and 95,500 Mcf, amounting to $0.2 million in natural gas receipts. After deducting $0.1 million in revenue deductions for taxes and transportation expenses, a total of $0.3 million was withheld by the operator from the Underlying Properties in the year ended December 31, 2016.

Since the beginning of the recoupment period, these properties would have contributed approximately 12,200 Bbls, amounting to $0.5 million in oil receipts, and 417,200 Mcf, amounting to $1.2 million in natural gas receipts. After deducting $0.6 million in revenue deductions for taxes and transportation expenses, a total of $1.1 million has been withheld by the operator.

11. SUBSEQUENT EVENTS

Underlying Properties Transactions

In January 2019, the Sponsor completed the sale of certain of the Underlying Properties located in Glasscock County, Texas for a total purchase price of approximately $62,000 (approximately $49,000 net to the Trust’s 80% net profits interest). The daily production associated with this acreage equated to less than 0.02% of daily oil production from the Underlying Properties.

Also in January 2019, the Sponsor entered into a lease arrangement with a private equity-backed operator with respect to a portion of the mineral rights relating to certain of the Underlying Properties located in Gaines County, Texas (no current production is associated with these mineral acres), for total proceeds of $160,000 ($128,000 net to the Trust’s 80% net profits interest). This lease allows the Trust to benefit from an upfront cash bonus as well as a 25% royalty on future production without the associated capital costs. In accordance with the Conveyance, the portion of the proceeds from these transactions attributable to the Trust’s interests in the related properties will be offset against costs and expenses attributable to January 2019 production and will be reflected in the March 2019 distribution announcement.

Distributions Paid or Declared

Subsequent to December 31, 2018, the Trust declared the following distributions:

Declaration Date	Record Date	Payment Date	Distribution per Unit
January 18, 2019	January 31, 2019	February 14, 2019	$ 0.005135
February 15, 2019	February 28, 2019	March 14, 2019	$ 0.026547

PERMIANVILLE ROYALTY TRUST
UNAUDITED SUPPLEMENTARY INFORMATION

Oil and Natural Gas Producing Activities

Oil and Natural Gas Reserve Quantities

Estimates of proved reserves attributable to the Trust and the related valuations were based 100% on reports prepared by the Trust's independent petroleum engineers, Cawley, Gillespie & Associates, Inc. Estimates were prepared in accordance with guidelines prescribed by the SEC and the Financial Accounting Standards Board, which require that reserve estimates be prepared under existing economic and operating conditions based upon an average of the first-day-of-the-month commodity price during the 12-month period ending on the balance sheet date with no provision for price and cost escalations except by contractual arrangements. Prices used in estimating reserves were as follows:

	2018	2017	2016
Oil (per Bbl)	$ 65.56	$ 51.34	$ 42.75
Natural gas (per Mcf)	$ 3.10	$ 2.98	$ 2.48

Proved reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revisions of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The process of estimating quantities of oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reserve. Consequently, these estimates are expected to change as additional information becomes available in the future.

As of December 31, 2018, 2017, and 2016, all of the Underlying Properties' oil and natural gas reserves were attributable to properties within the United States. Proved reserves attributable to the Trust and related standardized measure valuations are prepared on an accrual basis, which is the basis on which Enduro and, following the Sale Transaction, the Sponsor, and the Underlying Properties maintain their production records and is different from the basis on which the Trust production records are computed. The following is a summary of the changes in quantities of proved oil and natural gas reserves attributable to the Trust for the periods indicated:

	Trust Net Profits Interest		
	Oil (1) (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Balance—January 1, 2016	3,720	6,808	4,855
Extensions and discoveries	5	5	6
Revisions of previous estimates	(1,102)	699	(986)
Income from Net Profits Interest	(108)	(1,818)	(411)
Balance—December 31, 2016	2,515	5,694	3,464
Extensions and discoveries	92	2,638	531
Revisions of previous estimates	624	167	652)
Sales of Net Profits Interest	(45)	(373)	(107
Income from Net Profits Interest	(89)	(1,094)	(271)
Balance—December 31, 2017	3,097	7,032	4,269
Extensions and discoveries	177	6,611	1,279
Revisions of previous estimates	1,003	4,165	1,697
Income from Net Profits Interest	(103)	(1,446)	(344)
Balance—December 31, 2018	4,174	16,362	6,901
Proved developed reserves:			
December 31, 2016	2,515	5,694	3,464
December 31, 2017	3,055	6,950	4,213
December 31, 2018	3,954	9,656	5,563
Proved undeveloped reserves:			
December 31, 2016	—	—	—
December 31, 2017	42	82	56
December 31, 2018	219	6,707	1,337

(1) Reserves for natural gas liquids are immaterial and included as a component of oil reserves.

Extensions and discoveries. During the year ended December 31, 2018, extensions and discoveries were primarily related to an increase in the development of the Wolfcamp shale in the Permian Basin of west Texas and increasing activity in the Haynesville shale of Louisiana. In 2018, six gross (0.5 net) wells were drilled in the Wolfcamp Shale. In addition, 10 gross (1.4 net) locations were added as proved undeveloped reserves (totaling 15 gross, 2.6 net). During the year ended December 31, 2017, extensions and discoveries were primarily related to development activity in the Haynesville Shale in north Louisiana and the Pecos Valley field in west Texas. In 2017, six gross (0.5 net) wells were drilled in the Haynesville Shale and included as extensions. During the year ended December 31, 2016, capital development activity on the Underlying Properties was limited and, as a result, there were minimal extensions and discoveries.

Revisions of previous estimates. During the year ended December 31, 2018, revisions of previous estimates increased oil reserves by 32%, primarily due to an increase in the average oil price used to estimate future net reserves. The NYMEX average oil price of $65.56 per Bbl used to determine reserves as of December 31, 2018 was 28% higher than the $51.34 per Bbl average NYMEX oil price as of December 31, 2017.

During the year ended December 31, 2017, revisions of previous estimates increased oil reserves by 25%, primarily due to an increase in the average oil price used to estimate future net reserves. The NYMEX average oil price of $51.34 per Bbl used to determine reserves as of December 31, 2017 was 20%

higher than the $42.75 per Bbl average NYMEX oil price as of December 31, 2016.

During the year ended December 31, 2016, revisions of previous estimates decreased oil reserves by 30%, primarily as a result of a decrease in the average oil price used to determine estimated future net reserves. The NYMEX average oil price of $42.75 per Bbl used to determine reserves as of December 31, 2016 was 15% lower than the $50.28 per Bbl average NYMEX oil price as of December 31, 2015.

Sales of net profits interest. As discussed in Note 4 of the Notes to Financial Statements, during the year ended December 31, 2017, the Trust divested of its Net Profits Interest in certain oil and natural gas properties in the Permian Basin. As a result of this divestiture, the proved reserves associated with the producing properties reduced the Trust's total proved reserves on a BOE basis by approximately 3%.

Income from net profits interest. Income from net profits interest represents the reduction in total proved reserves as a result of net profits allocable to the Trust from the Underlying Properties during the applicable year, expressed as oil and natural gas reserve volumes.

During the year ended December 31, 2018, as a result of higher levels of oil and gas production and improved commodity prices, net profits allocable to the Trust were increased compared to the prior year, thereby increasing the income from net profits expressed as reserves.

During the year ended December 31, 2017, as a result of increased capital development activity, net profits allocable to the Trust were reduced compared to the prior year, thereby reducing the income from net profits expressed as reserves.

During the year ended December 31, 2016, the reduction in oil reserves as a result of the realized income from net profits interest declined from the prior year due to reduced oil revenues. This decline was the result of decreased commodity pricing, thereby reducing the oil net profits attributable to the Trust. The reduction in natural gas volumes due to the realized income from net profits increased from the prior year as a result of reduced direct operating expenses. A reduction in direct operating expenses caused the net profit interest attributable to the Trust from natural gas to increase, thereby increasing the deduction.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is computed by applying commodity prices used in determining proved reserves (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10% per year to reflect the estimated timing of the future cash flows. Future cash inflows were computed by applying the commodity prices utilized in determining proved reserves to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions. As the Trust is not subject to federal income taxes, future income taxes have been excluded.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves attributable to the Trust was as follows as of the dates indicated:

	December 31,		
	2018	2017	2016
	(in thousands)		
Future cash inflows	$ 256,938	$ 148,063	$ 98,223
Future production taxes	(20,892)	(12,081)	(8,127)
Future net cash flows	$ 236,046	$ 135,982	$ 90,096
10% annual discount for estimated timing of cash flows	(125,037)	(69,041)	(46,236)
Standardized measure of discounted future net cash flows	$ 111,009	$ 66,941	$ 43,860

The changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves attributable to the Trust for the periods indicated were as follows (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Extensions, discoveries, and other additions	$ 9,155	$ 5,088	$ 205
Sales of Net Profits Interest	—	(980)	—
Accretion of discount	19,559	4,386	7,838
Revisions of previous estimates and other	30,155	22,257)	(33,139)
Income from Net Profits Interest	(14,801)	(7,670)	(9,424)
Change in present value of future net revenues	44,068	23,081	(34,520)
Balance, beginning of period	66,941	43,860	78,380
Balance, end of year	$ 111,009	$ 66,941	$ 43,860

Selected Quarterly Financial Data

The following table provides selected quarterly financial data for the periods indicated:

	Quarter			
	First	Second	Third	Fourth
Year Ended December 31, 2018:				
Income from Net Profits Interest	$ 2,523,247	$ 4,583,033	$ 4,939,863	$ 3,140,638
Distributable income	$ 2,373,261	$ 4,432,989	$ 4,789,850	$ 2,758,636
Distributions per unit	$ 0.071917	$ 0.134333	$ 0.145147	$ 0.083595
Income from sale of Net Profits Interest on undeveloped acreage	$ —	$ —	$ 751,732	$ —
Year Ended December 31, 2017:				
Income from Net Profits Interest	$ 2,378,074	$ 3,546,015	$ 1,549,611	$ 170,260
Income from sale of Net Profits Interest on undeveloped acreage	$ —	$ —	$ —	$ 36,300,165

Income from sale of Net Profits Interest on producing properties	$ —	$ —	$ —	$ 1,650,000
Distributable income	$ 2,228,028	$ 3,271,026	$ 1,174,602	$ 38,070,417
Distributions per unit	$ 0.067516	$ 0.099122	$ 0.035594	$ 1.153649

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

None.

Item 9A. ***Controls and Procedures.***

Evaluation of Disclosure Controls and Procedures. The Trustee conducted an evaluation of the Trust's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act). Based on this evaluation, the Trustee has concluded that the disclosure controls and procedures of the Trust were effective, as of the end of the period covered by this report, in ensuring that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Trustee to allow timely decisions regarding required disclosure.

Due to the nature of the Trust as a passive entity and in light of the contractual arrangements pursuant to which the Trust was created, including the provisions of (i) the Trust Agreement and (ii) the Conveyance, the Trustee's disclosure controls and procedures related to the Trust necessarily rely on (A) information provided by COERT, including information relating to results of operations, the costs and revenues attributable to the Trust's interest under the Conveyance and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the Underlying Properties and the Net Profits Interest, and (B) conclusions and reports regarding reserves by the Trust's independent reserve engineers.

Changes in Internal Control over Financial Reporting. During the quarter ended December 31, 2018, there were no changes in the Trust's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of COERT.

TRUSTEE'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Exchange Act. Internal control over financial reporting is a process to provide reasonable assurance regarding the reliability of financial reporting for external purposes in accordance with the modified cash basis of accounting. The Trustee conducted an evaluation of the effectiveness of the Trust's internal control over financial reporting based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Trustee's evaluation under the framework in *Internal Control—Integrated Framework (2013)*, the Trustee concluded that the Trust's internal control over financial reporting was effective as of December 31, 2018. The independent registered public accounting firm of Ernst & Young LLP, the independent registered accounting firm that audited the financial statements of the Trust in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Trust's internal control over financial reporting as of December 31, 2018, which is included in this Item 9A.

Report of Independent Registered Public Accounting Firm

To the Trustee and Unitholders of Permianville Royalty Trust

Opinion on Internal Control over Financial Reporting

We have audited Permianville Royalty Trust's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). In our opinion, Permianville Royalty Trust (the Trust) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the statements of assets, liabilities, and trust corpus of Permianville Royalty Trust as of December 31, 2018 and 2017, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2018, and the related notes and our report dated March 18, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

The Trustee 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 Trustee'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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Trust in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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 included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

An entity'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. An entity'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 entity; (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 entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity'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.

/s/ Ernst & Young LLP

Fort Worth, Texas
March 18, 2019

Item 9B. ***Other Information.***

None.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance.***

The Trust has no directors or executive officers. The Trustee is a corporate Trustee that may be removed by the affirmative vote of the holders of not less than a majority of the outstanding Trust Units at a meeting at which a quorum is present.

Section 16(a) Beneficial Ownership Reporting Compliance

The Trust has no directors or officers. Accordingly, only holders of more than 10% of the Trust's units are required to file with the SEC initial reports of ownership of units and reports of changes in such ownership pursuant to Section 16 under the Exchange Act. Based solely on a review of these reports and any such reports furnished to the Trustee, the Trustee is not aware of any person having failed to file on a timely basis the reports required by Section 16(a) of the Exchange Act during the most recent fiscal year.

Audit Committee and Nominating Committee

Because the Trust does not have a board of directors, it does not have an audit committee, an audit committee financial expert or a nominating committee.

Code of Ethics

The Trust does not have a principal executive officer, principal financial officer, principal accounting officer or controller and has not adopted a code of ethics applicable to such persons.

Item 11. ***Executive Compensation.***

Pursuant to the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee. During the year ended December 31, 2018, the Trustee received $202,018 in administrative fees and reimbursable expenses from the Trust. During the years ended December 31, 2017 and 2016, the Trustee received $200,997 and $201,032, respectively, in administrative fees and reimbursable expenses from the Trust. The Trust does not have any executive officers, directors or employees. The Trust does not have a board of directors, and it does not have a compensation committee.

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

(a) Security Ownership of Certain Beneficial Owners.

Based on filings with the SEC, the Trustee is not aware of any holders of 5% or more of the units as of March 6, 2019 except as set forth below. The following information has been obtained from public filings with the SEC.

Beneficial Owner	Trust Units Beneficially Owned	Percent of Class
Permianville Holdings LLC	8,600,000(1)	26.1%
Jerry Roger Kent	1,892,238(2)	5.7%

(1) Based on a Schedule 13D dated September 10, 2018 filed jointly by Permianville Holdings LLC ("Holdings"), Permianville Intermediary LLC—Series 1 ("Series 1 Intermediary"), Permianville Intermediary LLC—Series 2 ("Series 2 Intermediary"), Permianville Intermediary LLC—Series 3 ("Series 3 Intermediary"), Cross Ocean USSS Fund I (A) (Cayman) LP ("Cayman Feeder"), Cross Ocean USSS Fund I (A) Del Feeder LP ("DE Feeder"), Cross Ocean USSS SIF 1 LP ("Cross Ocean SIF"), Cross Ocean USSS GP LP ("Cross Ocean GP"), Cross Ocean USSS GP Ltd ("Cross Ocean Ltd"), Cross Ocean Partners Management LP ("Cross Ocean Management"), Cross Ocean Partners Management GP, LLC ("Management GP"), GG Managers LLC ("GG Managers") and Graham Goldsmith (collectively, all such persons and entities are referred to as the "Reporting Persons"). The principal business office address for the Reporting Persons is c/o Cross Ocean Partners Management LP, 20 Horseneck Lane, Greenwich, CT 06830.

According to the filing, Holdings has sole voting power and dispositive power with respect to 8,600,000 Trust Units. Each of Cross Ocean Management, Management GP, GG Managers and Graham Goldsmith has shared voting power and shared dispositive power with respect to such shares. Each of Series 1 Intermediary and Series 2 Intermediary has shared voting power and shared dispositive power with respect to 2,293,053 Trust Units. Series 3 Intermediary has shared voting power and shared dispositive power with respect to 2,293,052 Trust Units. Cayman Feeder has shared voting power and shared dispositive power with respect to 1,165,871 Trust Units. DE Feeder has shared voting power and shared dispositive power with respect to 1,720,842 Trust Units. Cross Ocean SIF has shared voting power and shared dispositive power with respect to 2,233,017 Trust Units. Each of Cross Ocean GP and Cross Ocean Ltd has shared voting power and shared dispositive power with respect to 5,119,730 Trust Units.

According to the filing, each of Series 1 Intermediary, Series 2 Intermediary, Series 3 Intermediary and DE Feeder, by virtue of their relationships to Holdings, may be deemed to beneficially own the Trust Units that Holdings beneficially owns, but each disclaims beneficial ownership of such Trust Units. Each of Cross Ocean Cayman and Cross Ocean SIF, by virtue of their relationships to Series 1 Intermediary, Series 2 Intermediary and Series 3 Intermediary, may be deemed to beneficially own the Trust Units that Holdings beneficially owns, but each disclaims beneficial ownership of such Trust Units. Each of Cross Ocean GP, Cross Ocean Ltd, Cross Ocean Management, Management GP, GG Managers and Graham Goldsmith, by virtue of their relationships to each other and to Cross Ocean Cayman, DE Feeder and Cross Ocean SIF, may be deemed to beneficially own the Trust Units that Holdings beneficially owns, but each disclaims beneficial ownership of such Trust Units.

(2) Based on a Schedule 13G/A filed with the SEC on February 12, 2018 by Jerry Roger Kent. The principal business office address for the reporting person is 4695 Preston Park Blvd., Suite 170 East, Plano, Texas 75093-5180. According to the filing, the reporting person has sole voting power with

respect to 1,062,038 Trust Units, shared voting power with respect to 830,000 Trust Units, sole dispositive power with respect to 1,062,038 Trust Units, and shared dispositive power with respect to 830,000 Trust Units.

(b) Security Ownership of Management.

Not applicable.

(c) Changes in Control.

The registrant knows of no arrangement, including any pledge by any person of securities of the registrant or any of its parents, the operation of which may at a subsequent date result in a change of control of the registrant. See "Certain Relationships and Related Transactions, and Director Independence—Registration Rights Agreement" in Item 13 of this Form 10-K.

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

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $200,000 to the Trustee and $2,000 to the Delaware Trustee.

Registration Rights Agreement. The Trust and COERT (as the assignee of Enduro as a result of the Sale Transaction) are parties to a Registration Rights Agreement, as amended, whereby COERT, its affiliates and certain permitted transferees holding registrable Trust Units are entitled, upon receipt by the Trustee of written notice from holders of a majority of the then outstanding registrable Trust Units, to demand that the Trust effect the registration of the registrable Trust Units. The holders of the registrable Trust Units are entitled to demand a maximum of five such registrations. In connection with the preparation and filing of any registration statement, COERT will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust. Any underwriting discounts and commissions will be borne by the seller of the Trust Units. The foregoing description of the Registration Rights Agreement is qualified in its entirety by the terms of the Registration Rights Agreement, and Amendment No. 1 thereto, copies of which are incorporated by reference as exhibits to this Form 10-K.

Director Independence

The Trust does not have a board of directors.

Item 14. *Principal Accounting Fees and Services.*

The Trust does not have an audit committee. Any pre-approval and approval of all services performed by the principal auditor or any other professional service firms and related fees are granted by the Trustee. During the years ended December 31, 2018, 2017 and 2016, Ernst & Young, LLP served as the Trust's independent registered public accounting firm. The Trustee also has appointed Ernst & Young, LLP as the independent registered public accounting firm to audit the Trust's financial statements for the fiscal year ending December 31, 2018.

The following table presents the aggregate fees billed to the Trust for the years ended December 31, 2018, 2017 and 2016 by Ernst & Young, LLP:

	2018	2017	2016
Audit fees(1)	$ 412,883	$ 181,367	$ 137,516
Audit-related fees	—	—	—
Tax fees	—	—	—
All other fees	—	—	—
Total fees	$ 412,883	$ 181,367	$ 137,516

(1) Fees billed for professional services rendered for the integrated audit of the Trust's financial statements and reviews of the financial statements included in the Trust's quarterly reports.

PART IV

Item 15. *Exhibits, Financial Statement Schedules.*

(a)(1) Financial Statements

The following financial statements are set forth under “Financial Statements and Supplementary Data” in Item 8 of this Form 10-K on the pages indicated:

(a)(2) Schedules

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

(a)(3) Exhibits

See Index to Exhibits.

Item 16. *Form 10-K Summary.*

None.

Table of Contents

INDEX TO EXHIBITS

Exhibit Number	Description
2.1*	Agreement and Plan of Merger of Enduro Royalty Trust and Enduro Texas LLC, dated as of November 3, 2011 by and between the Bank of New York Mellon Trust Company, N.A., as Trustee of Enduro Royalty Trust, and Enduro Texas LLC. (Incorporated herein by reference to Exhibit 1.2 to our Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
3.1*	Certificate of Trust of Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 3.3 to the Registration Statement on Form S-1, filed on May 16, 2011 (Registration No. 333-174225))
3.2*	Certificate of Amendment to Certificate of Trust. (Incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on September 5, 2018 (File No. 1-35333))
3.3*	Amended and Restated Trust Agreement of Enduro Royalty Trust, dated November 3, 2011, among Enduro Resource Partners LLC, The Bank of New York Mellon Trust Company, N.A., as Trustee of Enduro Royalty Trust, and Wilmington Trust Company, as Delaware Trustee of Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 3.1 to our Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
3.4*	First Amendment to Amended and Restated Trust Agreement, dated September 6, 2017 but effective as of August 30, 2017, among Enduro Resource Partners LLC, Wilmington Trust Company, as Delaware Trustee, and The Bank of New York Mellon Trust Company, N.A., as Trustee. (Incorporated herein by reference to Exhibit 3.1 to our Current Report on Form 8-K filed on September 12, 2017 (File No. 1-35333))
3.5*	Second Amendment to Amended and Restated Trust Agreement of Enduro Royalty Trust, dated September 14, 2018, among COERT Holdings 1 LLC, Wilmington Trust Company, as Delaware trustee, and The Bank of New York Mellon Trust Company, N.A., as trustee. (Incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on September 14, 2018 (File No. 1-35333))
4.1*	Registration Rights Agreement, dated as of November 8, 2011, by and between Enduro Resource Partners LLC and Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 10.3 to our Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
4.2*	Amendment No. 1 to Registration Rights Agreement, dated as of November 8, 2012, by and between Enduro Resource Partners LLC and Permianville Royalty Trust. (Incorporated herein by reference to Exhibit 4.2 to our Annual Report on Form 10-K for the year ended December 31, 2012 (File no. 1-35333))
10.1*	Conveyance of Net Profits Interest, dated November 8, 2011, by and between Enduro Operating LLC and Enduro Texas LLC. (Incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
10.2*	Supplement to Conveyance of Net Profits Interest, dated November 8, 2011, from Enduro Operating LLC, Enduro Texas LLC and The Bank of New York Mellon Trust Company, N.A. as Trustee of Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on November 8, 2011 (File No. 1-35333))
10.3*	First Amendment to Conveyance of Net Profits Interest, dated September 6, 2017, among Enduro Operating LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee of Enduro Royalty Trust. (Incorporated herein by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on September 12, 2017 (File No. 1-35333))
10.4*	Partial Release, Reconveyance and Termination Agreement, dated September 6, 2017, by and between The Bank of New York Mellon Trust Company, N.A., as Trustee of Enduro Royalty Trust, and Enduro Operating LLC. (Incorporated herein by reference to Exhibit 10.2 to our Current Report on Form 8-K filed on September 12, 2017 (File No. 1-35333))
23.1	Consent of Cawley, Gillespie & Associates, Inc.
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1	Report of Cawley, Gillespie & Associates, Inc.

* Asterisk indicates exhibit previously filed with the SEC and incorporated herein by reference.

SIGNATURES

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

Date: March 18, 2019	PERMIANVILLE ROYALTY TRUST
	By: THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A., AS TRUSTEE
	By: /s/ SARAH NEWELL
	Name: **Sarah Newell**
	Title: *Vice President*

The Registrant, Permianville Royalty Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided. In signing the report above, the Trustee does not imply that it has performed any such function or that such function exists pursuant to the terms of the Trust Agreement under which it serves.

Exhibit 23.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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AUSTIN, TEXAS 78729-1707
512-249-7000

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HOUSTON, TEXAS 77002-5008
713-651-9944

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the use of the oil and gas reserve information in the Permianville Royalty Trust Securities and Exchange Commission Form 10-K for the year ended December 31, 2018, based on the reserve report dated February 8, 2019. We also consent to the inclusion of our report dated February 8, 2019 as an exhibit to the Form 10-K.

W. Todd Brooker, P.E.
Senior Vice President
Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

Fort Worth, Texas
March 18, 2019

EXHIBIT 31.1

CERTIFICATION

I, Sarah Newell, certify that:

1. I have reviewed this annual report on Form 10-K of Permianville Royalty Trust, for which The Bank of New York Mellon Trust Company, N.A., acts as Trustee;

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, distributable income and changes in Trust corpus 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)), or for causing such controls and procedures to be established and maintained, for the registrant and I have:

a) Designed such disclosure controls and procedures, or caused such 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;

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;

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:

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves any persons who have a significant role in the registrant's internal control over financial reporting.

In giving the foregoing certifications in paragraphs 4 and 5, I have relied to the extent I consider reasonable on information provided to me by COERT Holdings 1 LLC.

Date: March 18, 2019	/s/ SARAH NEWELL
	Sarah Newell
	Vice President
	The Bank of New York Mellon Trust Company, N.A., as Trustee

EXHIBIT 32.1

March 18, 2019

Via EDGAR

Securities and Exchange Commission
100 F Street, N.E.
Washington, D.C. 20549

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

Ladies and Gentlemen:

In connection with the Annual Report of Permianville Royalty Trust (the “Trust”) on Form 10-K for the year ended December 31, 2018 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned, not in its individual capacity but solely as the Trustee of the Trust, certifies pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to its knowledge:

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

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

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

The Bank of New York Mellon Trust Company,
N.A., Trustee for Permianville Royalty Trust

By: /s/ SARAH NEWELL
Sarah Newell
Vice President and Trust Officer

Exhibit 99.1

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

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AUSTIN, TEXAS 78729-1106
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HOUSTON, TEXAS 77002-5008
713-651-9944

February 8, 2019

Ms. Sarah Newell
Permianville Royalty Trust
The Bank of New York Mellon Trust Company, N.A., Trustee
919 Congress Avenue, Suite 500
Austin, TX 78701

Re: Evaluation—Total Proved Reserves
Permianville Royalty Trust Net Profit Interests
Derived From Permianville Resource Partners LLC
Underlying Properties Total Controlled Interests
Texas, Louisiana and New Mexico Properties
Using Year-end SEC Prices as of December 31, 2018

Pursuant to the Guidelines of the Securities and Exchange Commission for Reporting Corporate Reserves and Future Net Revenue

Dear Ms. Newell:

As requested, this report was prepared on February 8, 2019 for Permianville Royalty Trust ("Trust") for the purpose of submitting our estimates of total proved reserves and forecasts of economics attributable to the Trust net profits interests. We evaluated 100% of the Trust reserves, which are made up of oil and gas properties in Texas, Louisiana and New Mexico controlled by COERT Holdings 1, LLC ("Company"). This evaluation utilized an effective date of December 31, 2018, was prepared using constant prices and costs, and conforms to Item 1202(a)(8) of Regulation S-K and other rules of the *Securities and Exchange Commission* (SEC). Composite summaries of the proved reserves for both the total controlled interests and the net profits interests are presented below.

Total Controlled Interests

		Proved Developed Producing	Proved Developed	Proved Undeveloped	Total Proved
Net Reserves					
Oil	– Mbbl	10,856.3	10,856.3	524.0	11,380.3
Gas	– MMcf	25,486.2	25,486.2	16,687.7	42,173.8
Revenue					
Oil	– M$	583,608.8	583,608.8	26,034.5	609,643.3
Gas	– M$	51,716.2	51,716.2	35,756.2	87,472.4
Net Taxes	– M$	52,894.2	52,894.2	3,563.6	56,457.8
Operating Expenses	– M$	316784.6	316784.6	7,985.4	324,770.1
Investments	– M$	0.0	0.0	27,247.4	27,247.4
Net Operating Income (BFIT)	– M$	265,646.2	265,646.2	22,994.3	288,640.5
Discounted at 10%	**– M$**	**126,295.2**	**126,295.2**	**6,700.3**	**132,995.5**

Net Profits Interests

		Proved Developed Producing	Proved Developed	Proved Undeveloped	Total Proved
Net Reserves					
Oil	– Mbbl	3,954.0	3,954.0	219.0	4,174.0
Gas	– MMcf	9,656.0	9,656.0	6,707.0	16,362.0
Revenue					
Oil	– M$	212,239.0	212,239.0	10,785.0	223,024.0
Gas	– M$	19,563.0	19,563.0	14,353.0	33,916.0
Net Taxes	– M$	19,282.0	19,282.0	1,610.0	20,892.0
Operating Expenses	– M$	0.0	0.0	0.0	0.0
Investments	– M$	0.0	0.0	0.0	0.0
Net Operating Income (BFIT)	– M$	212,518.0	212,518.0	23,528.0	236,046.0
Discounted at 10%	**– M$**	**101,036.0**	**101,036.0**	**9,973.0**	**111,009.0**

Future revenue is prior to deducting state production taxes and ad valorem taxes. Future net cash flow is after deducting these taxes, future capital costs and operating expenses, but before consideration of federal income taxes. In accordance with SEC guidelines, the future net cash flow has been discounted at an annual rate of ten percent to determine its "present worth". The present worth is shown to indicate the effect of time on the value of money and should not be construed as being the fair market value of the properties.

The oil reserves include oil, condensate, and NGL. Oil volumes are expressed in barrels (42 U.S. gallons). Gas volumes are expressed in thousands of standard cubic feet (Mcf) at contract temperature and pressure base.

Our estimates are for proved reserves only and do not include any probable or possible reserves nor have any values been attributed to interest in acreage beyond the location for which undeveloped reserves have been estimated.

Net Profit Calculation

The net profits interests entitle the Trust to receive 80% of the net proceeds attributable to the Company interest from the sale of production from the underlying properties.

Hydrocarbon Pricing

The base SEC oil and gas prices calculated for December 31, 2018 were $65.56/bbl and $3.100/MMBTU, respectively. As specified by the SEC, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The base oil price is based upon WTI-Cushing spot prices (EIA) during 2018 and the base gas price is based upon Henry Hub spot prices (EIA) during 2018.

The base prices were adjusted for differentials on a per-property basis, which may include local basis differentials, transportation, gas shrinkage, gas heating value (BTU content) and/or crude quality and gravity corrections. After these adjustments, the net realized prices for the SEC price case over the life of the proved properties was estimated to be $53.57 per barrel for oil and $2.07 per MCF for gas. All economic factors were held constant in accordance with SEC guidelines.

Economic Parameters

Ownership was accepted as furnished and has not been independently confirmed. Oil and gas price differentials, lease operating expenses (LOE), workover expenses, overhead expenses and investments were calculated and prepared by Company and were thoroughly reviewed by us for accuracy and completeness. LOE was determined at the well level using averages determined from historical lease operating statements. All economic parameters, including expenses and investments, were held constant (not escalated) throughout the life of these properties.

Severance tax rates were applied at normal state percentages of oil and gas revenue. Ad valorem taxes were applied to each property as provided by your office.

Possible Effects of Federal and State Legislation

Federal, state and local laws and regulations, which are currently in effect and that govern the development and production of oil and natural gas, have been considered in the evaluation of proved reserves for this report. However, the impact of possible changes to legislation or regulations to future operating expenses and investment costs have not been included in the evaluation. These possible changes could have an effect on the reserves and economics. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

SEC Conformance and Regulations

The reserve classifications and the economic considerations used herein for the SEC pricing scenario conform to the criteria of the SEC as defined in pages 3 and 4 of the Appendix. The reserves and economics are predicated on regulatory agency classifications, rules, policies, laws, taxes and royalties currently in effect except as noted herein. The possible effects of changes in legislation or other Federal or State restrictive actions which could affect the reserves and economics have not been considered. However, we do not anticipate nor are we aware of any legislative changes or restrictive regulatory actions that may impact the recovery of reserves.

Reserve Estimation Methods

The methods employed in estimating reserves are described in page 2 of the Appendix. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy.

Non-producing reserve estimates, for both developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for the Company properties, due to the mature nature of their properties targeted for development and an abundance of subsurface control data. The assumptions, data, methods and procedures used herein are appropriate for the purpose served by this report.

<u>General Discussion</u>

The estimates and forecasts were based upon interpretations of data furnished by your office and available from our files. To some extent information from public records has been used to check and/or supplement these data. The basic engineering and geological data were subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. All estimates represent our best judgment based on the data available at the time of preparation. Due to inherent uncertainties in future production rates, commodity prices and geologic conditions, it should be realized that the reserve estimates, the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

An on-site field inspection of the properties has not been performed. The mechanical operation or condition of the wells and their related facilities have not been examined nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered. The cost of plugging and the salvage value of equipment at abandonment have not been included as part of the workover expenses described previously.

Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F-693), made up of independent registered professional engineers and geologists that have provided petroleum consulting services to the oil and gas industry for over 50 years. This evaluation was supervised by W. Todd Brooker, Senior Vice President at Cawley, Gillespie & Associates, Inc. and a State of Texas Licensed Professional Engineer (License #83462). We do not own an interest in the properties or Permianville Resource Partners LLC or Permianville Royalty Trust and are not employed on a contingent basis. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report. Our work-papers and related data utilized in the preparation of these estimates are available in our office. We consent to the filing of this report as an exhibit to the Annual Report on Form 10-K of Permianville Royalty Trust for the year-end December 31, 2018.

Yours very truly,

W. Todd Brooker

W. Todd Brooker, P.E.
Senior Vice President
CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm (F-693)

APPENDIX

Methods Employed in the Estimation of Reserves

The four methods customarily employed in the estimation of reserves are (1) *production performance*, (2) *material balance*, (3) *volumetric* and (4) *analogy*. Most estimates, although based primarily on one method, utilize other methods depending on the nature and extent of the data available and the characteristics of the reservoirs.

Basic information includes production, pressure, geological and laboratory data. However, a large variation exists in the quality, quantity and types of information available on individual properties. Operators are generally required by regulatory authorities to file monthly production reports and may be required to measure and report periodically such data as well pressures, gas-oil ratios, well tests, etc. As a general rule, an operator has complete discretion in obtaining and/or making available geological and engineering data. The resulting lack of uniformity in data renders impossible the application of identical methods to all properties, and may result in significant differences in the accuracy and reliability of estimates.

A brief discussion of each method, its basis, data requirements, applicability and generalization as to its relative degree of accuracy follows:

Production performance. This method employs graphical analyses of production data on the premise that all factors which have controlled the performance to date will continue to control and that historical trends can be extrapolated to predict future performance. The only information required is production history. Capacity production can usually be analyzed from graphs of rates versus time or cumulative production. This procedure is referred to as "decline curve" analysis. Both capacity and restricted production can, in some cases, be analyzed from graphs of producing rate relationships of the various production components. Reserve estimates obtained by this method are generally considered to have a relatively high degree of accuracy with the degree of accuracy increasing as production history accumulates.

Material balance. This method employs the analysis of the relationship of production and pressure performance on the premise that the reservoir volume and its initial hydrocarbon content are fixed and that this initial hydrocarbon volume and recoveries therefrom can be estimated by analyzing changes in pressure with respect to production relationships. This method requires reliable pressure and temperature data, production data, fluid analyses and knowledge of the nature of the reservoir. The material balance method is applicable to all reservoirs, but the time and expense required for its use is dependent on the nature of the reservoir and its fluids. Reserves for depletion type reservoirs can be estimated from graphs of pressures corrected for compressibility versus cumulative production, requiring only data that are usually available. Estimates for other reservoir types require extensive data and involve complex calculations most suited to computer models which makes this method generally applicable only to reservoirs where there is economic justification for its use. Reserve estimates obtained by this method are generally considered to have a degree of accuracy that is directly related to the complexity of the reservoir and the quality and quantity of data available.

Volumetric. This method employs analyses of physical measurements of rock and fluid properties to calculate the volume of hydrocarbons in-place. The data required are well information sufficient to determine reservoir subsurface datum, thickness, storage volume, fluid content and location. The volumetric method is most applicable to reservoirs which are not susceptible to analysis by production performance or material balance methods. These are most commonly newly developed and/or no-pressure depleting reservoirs. The amount of hydrocarbons in-place that can be recovered is not an integral part of the volumetric calculations but is an estimate inferred by other methods and a knowledge of the nature of the reservoir. Reserve estimates obtained by this method are generally considered to have a low degree of accuracy; but the degree of accuracy can be relatively high where rock quality and subsurface control is good and the nature of the reservoir is uncomplicated.

Analogy. This method which employs experience and judgment to estimate reserves, is based on observations of similar situations and includes consideration of theoretical performance. The analogy method is applicable where the data are insufficient or so inconclusive that reliable reserve estimates cannot be made by other methods. Reserve estimates obtained by this method are generally considered to have a relatively low degree of accuracy.

Much of the information used in the estimation of reserves is itself arrived at by the use of estimates. These estimates are subject to continuing change as additional information becomes available. Reserve estimates which presently appear to be correct may be found to contain substantial errors as time passes and new information is obtained about well and reservoir performance.

Reserve Definitions and Classifications

The Securities and Exchange Commission, in SX Reg. 210.4-10 dated November 18, 1981, as amended on September 19, 1989 and January 1, 2010, requires adherence to the following definitions of oil and gas reserves:

"(22) **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 a 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.

"(6) **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.

"(31) **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.

“(18) **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.

“(iv) See also guidelines in paragraphs (17)(iv) and (17)(vi) of this section (below).

“(17) **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 (22)(iii) of this section (above), 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.”

Instruction 4 of Item 2(b) of Securities and Exchange Commission Regulation S-K was revised January 1, 2010 to state that “a registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S—K.” This is relevant in that Instruction 2 to paragraph (a)(2) states: “The registrant is *permitted, but not required*, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item.”

“(26) **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.

“Note to paragraph (26): 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).”