

PERMIAN BASIN ROYALTY TRUST
Form 10-K
March 18, 2019
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2018

OR

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

Commission file number 1-8033

Permian Basin Royalty Trust

(Exact Name of Registrant as Specified in the Permian Basin Royalty Trust Indenture)

Texas

(State or Other Jurisdiction of

75-6280532

(I.R.S. Employer Identification No.)

Incorporation or Organization)

Royalty Trust Management

Simmons Bank

2911 Turtle Creek Boulevard

Suite 850

Dallas, Texas 75219

(Address of Principal Executive Offices; Zip Code)

(855) 588-7839

(Registrant's Telephone Number, Including Area Code)

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark 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 No

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

Indicate by check mark whether the registrant is 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 Accelerated filer Non-accelerated filer Smaller Reporting Company Emerging Growth Company
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.

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates 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 \$434,860,067.

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At March 1, 2019, there were 46,608,796 Units of Beneficial Interest of the Trust outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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FORWARD LOOKING INFORMATION

Certain information included in this report contains, and other materials filed or to be filed by the Trust with the Securities and Exchange Commission (as well as information included in oral statements or other written statements made or to be made by the Trust) may contain or include, forward looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. Such forward looking statements may be or may concern, among other things, capital expenditures, drilling activity, development activities, production efforts and volumes, hydrocarbon prices and the results thereof, and regulatory matters. Although the Trustee believes that the expectations reflected in such forward-looking statements are reasonable, such expectations are subject to numerous risks and uncertainties and the Trustee can give no assurance that they will prove correct. There are many factors, none of which are within the Trustee's control, that may cause such expectations not to be realized, including, among other things, factors such as actual oil and gas prices and the recoverability of reserves, capital expenditures, general economic conditions, actions and policies of petroleum-producing nations and other changes in the domestic and international energy markets and the factors identified under Item 1A, Risk Factors. Such forward looking statements generally are accompanied by words such as estimate, expect, predict, anticipate, goal, should, assume, believe, or other words that convey the uncertainty of events or outcomes.

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PART I

Item 1. Business

The Permian Basin Royalty Trust (the Trust) is an express trust created under the laws of the state of Texas by the Permian Basin Royalty Trust Indenture (the Trust Indenture) entered into on November 3, 1980, between Southland Royalty Company (Southland Royalty) and The First National Bank of Fort Worth, as Trustee. Simmons Bank, an Arkansas state-chartered bank (Simmons Bank), is now the Trustee of the Trust. The principal office of the Trust (sometimes referred to herein as the Registrant) is located at 2911 Turtle Creek Boulevard, Suite 850, Dallas, Texas (telephone number (855) 588-7839).

On January 9, 2014, Bank of America N.A. (as successor to The First National Bank of Fort Worth) gave notice to Unit holders that it would be resigning as trustee of the Trust subject to certain conditions that included the appointment of Southwest Bank as successor trustee. At a Special Meeting of Trust Unit holders, the Unit holders approved the appointment of Southwest Bank as successor trustee of the Trust once the resignation of Bank of America N.A. took effect and also approved certain amendments to the Trust Indenture. The effective date of Bank of America N.A.'s resignation and the effective date of Southwest Bank's appointment as successor trustee was August 29, 2014.

Effective October 19, 2017, Simmons First National Corporation (SFNC) completed its acquisition of First Texas BHC, Inc., the parent company of Southwest Bank. SFNC is the parent company of Simmons Bank. SFNC merged Southwest Bank with Simmons Bank effective February 20, 2018. The defined term Trustee as used herein shall refer to Bank of America N.A. for periods prior to August 29, 2014, and shall refer to Southwest Bank for periods from August 29, 2014 through February 19, 2018 and shall refer to Simmons Bank for periods on and after February 20, 2018.

On October 23, 1980, the stockholders of Southland Royalty approved and authorized that company's conveyance of net overriding royalty interests (equivalent to net profits interests) to the Trust for the benefit of the stockholders of Southland Royalty of record at the close of business on the date of the conveyance consisting of a 75% net overriding royalty interest carved out of that company's fee mineral interests in the Waddell Ranch properties in Crane County, Texas and a 95% net overriding royalty interest carved out of that company's major producing royalty properties in Texas. The conveyance of these interests (the Royalties) was made on November 3, 1980, effective as to production from and after November 1, 1980 at 7:00 a.m. The properties and interests from which the Royalties were carved and which the Royalties now burden are collectively referred to herein as the Underlying Properties. The Underlying Properties are more particularly described under Item 2. Properties herein.

The function of the Trustee is to collect the income attributable to the Royalties, to pay all expenses and charges of the Trust, and then to distribute the remaining available income to the Unit holders. The Trust is not empowered to carry on any business activity and has no employees, all administrative functions being performed by the Trustee.

The Royalties constitute the principal asset of the Trust and the beneficial interests in the Royalties are divided into that number of Units of Beneficial Interest (the Units) of the Trust equal to the number of shares of the common stock of Southland Royalty outstanding as of the close of business on November 3, 1980. Each stockholder of Southland Royalty of record at the close of business on November 3, 1980, received one Unit for each share of the common stock of Southland Royalty then held.

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In 1985, Southland Royalty became a wholly-owned subsidiary of Burlington Northern Inc. (BNI). In 1988, BNI transferred its natural resource operations to Burlington Resources Inc. (BRI) as a result of which Southland Royalty became a wholly-owned indirect subsidiary of BRI. As a result of this transfer, Meridian Oil Inc., a Delaware corporation (MOI), which was the parent company of Southland Royalty, became a wholly owned direct subsidiary of BRI. Effective January 1, 1996, Southland Royalty was merged with and into MOI. As a result of this merger, the separate corporate existence of Southland Royalty ceased and MOI survived and succeeded to the ownership of all of the assets of Southland Royalty and assumed all of its rights, powers, privileges, liabilities and obligations. Effective July 11, 1996, MOI changed its name to Burlington Resources Oil & Gas Company, now Burlington Oil & Gas Company LP (BROG). Any reference

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to BROG hereafter for periods prior to the occurrence of the aforementioned name change or merger should, as applicable, be construed to be a reference to MOI or Southland Royalty. Further, BROG notified the Trust that, on February 14, 1997, the Texas Royalty properties (as defined herein on page 8) that are subject to the Net Overriding Royalty Conveyance dated November 1, 1980 (the Texas Royalty Conveyance), were sold to Riverhill Energy Corporation (Riverhill Energy) of Midland, Texas. Effective March 31, 2006, ConocoPhillips acquired BRI pursuant to a merger between BRI and a wholly-owned subsidiary of ConocoPhillips. As a result of this acquisition, BRI and BROG are both wholly-owned subsidiaries of ConocoPhillips.

The term net proceeds is used in the above described conveyance and means the excess of gross proceeds received by BROG during a particular period over production costs for such period. Gross proceeds means the amount received by BROG (or any subsequent owner of the Underlying Properties) from the sale of the production attributable to the Underlying Properties, subject to certain adjustments. Production costs means, generally, costs incurred on an accrual basis in operating the Underlying Properties, including both capital and non-capital costs; for example, development drilling, production and processing costs, applicable taxes, and operating charges. If production costs exceed gross proceeds in any month, the excess is recovered out of future gross proceeds prior to the making of further payment to the Trust, but the Trust is not liable for any production costs or liabilities attributable to these properties and interests or the minerals produced therefrom. If at any time the Trust receives more than the amount due from the Royalties, it shall not be obligated to return such overpayment, but the amounts payable to it for any subsequent period shall be reduced by such overpaid amount, plus interest, at a rate specified in the conveyance.

To the extent it has the legal right to do so, BROG is responsible for marketing the production from such properties and interests, either under existing sales contracts or under future arrangements at the best prices and on the best terms it shall deem reasonably obtainable in the circumstances. BROG also has the obligation to maintain books and records sufficient to determine the amounts payable to the Trustee. BROG, however, can sell its interests in the Underlying Properties.

Proceeds from production in the first month are generally received by BROG in the second month, the net proceeds attributable to the Royalties are paid by BROG to the Trustee in the third month and distribution by the Trustee to the Unit holders is made in the fourth month. The identity of Unit holders entitled to a distribution will generally be determined as of the last business day of each calendar month (the monthly record date). The amount of each monthly distribution will generally be determined and announced ten days before the monthly record date. Unit holders of record as of the monthly record date will be entitled to receive the calculated monthly distribution amount for each month on or before ten business days after the monthly record date. The aggregate monthly distribution amount is the excess of (i) net revenues from the Trust properties, plus any decrease in cash reserves previously established for contingent liabilities and any other cash receipts of the Trust over (ii) the expenses and payments of liabilities of the Trust plus any net increase in cash reserves for contingent liabilities.

Cash held by the Trustee as a reserve for liabilities or contingencies (which reserves may be established by the Trustee in its discretion) or pending distribution is placed, at the Trustee's discretion, in obligations issued by (or unconditionally guaranteed by) the United States or any agency thereof, repurchase agreements secured by obligations issued by the United States or any agency thereof, certificates of deposit of banks having a capital surplus and undivided profits in excess of \$50,000,000, or other interest bearing accounts in FDIC-insured state or national banks, including the Trustee, so long as the entire amount in such account is at all times fully insured by the FDIC, subject, in each case, to certain other qualifying conditions.

The income to the Trust attributable to the Royalties is not subject in material respects to seasonal factors nor in any manner related to or dependent upon patents, licenses, franchises or concessions. The Trust conducts no research activities. The Trust has no employees since all administrative functions are performed by the Trustee.

BROG has advised the Trustee that it believes that comparable revenues could be obtained in the event of a change in purchasers of production.

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Website/SEC Filings

Our Internet address is www.pbt-permian.com. You can review, free of charge, the filings the Trust has made with respect to its annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended. We shall post these reports to our Internet address as soon as reasonably practicable after we electronically file them with, or furnish them to, the SEC.

Widely Held Fixed Investment Trust Reporting Information

Some Trust Units are held by middlemen, 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 customer in 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. Simmons Bank, EIN: 71-0162300, 2911 Turtle Creek Boulevard, Suite 850, Dallas, Texas 75219, telephone number (855) 588-7839, email address trustee@pbt-permian.com, 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.pbt-permian.com. Notwithstanding the foregoing, the middlemen holding Trust Units on behalf of Unit holders, 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 Trust Units, including the issuance of IRS Forms 1099 and certain written tax statements. Unit holders 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.

Item 1A. Risk Factors

Crude oil and natural gas prices are volatile and fluctuate in response to a number of factors; Lower prices could reduce the net proceeds payable to the Trust and Trust distributions.

The Trust's monthly distributions are highly dependent upon the prices realized from the sale of crude oil and natural gas and a material decrease in such prices could reduce the amount of cash distributions paid to Unit holders. Crude 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. Factors that contribute to price fluctuation include, among others:

political conditions in major oil producing regions, especially in the Middle East;

worldwide economic conditions;

weather conditions;

the supply and price of domestic and foreign crude oil or natural gas;

the ability of members of the Organization of Petroleum Exporting Countries to agree upon and maintain oil prices and production levels;

the level of consumer demand;

the price and availability of alternative fuels;

the proximity to, and capacity of, transportation facilities;

the effect of worldwide energy conservation measures; and

the nature and extent of governmental regulation and taxation.

When crude oil and natural gas prices decline, the Trust is affected in two ways. First, net income from the Royalties is reduced. Second, exploration and development activity on the Underlying Properties may decline as some projects may become uneconomic and are either delayed or eliminated. It is impossible to predict future crude oil and natural gas price movements, and this reduces the predictability of future cash distributions to Unit holders.

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Increased production and development costs attributable to the Royalties will result in decreased Trust distributions unless revenues also increase.

Production and development costs attributable to the Royalties are deducted in the calculation of the Trust's share of net proceeds. Accordingly, higher or lower production and development costs will directly decrease or increase the amount received by the Trust from the Royalties. Production and development costs are impacted by increases in commodity prices, both directly, through commodity price dependent costs, such as electricity, and indirectly, as a result of demand driven increases in costs of oilfield goods and services. For example, the costs of electricity that will be included in production and development costs deducted in calculating the Trust's share of 2019 net proceeds could increase compared to the electrical costs incurred during 2018 if higher fuel surcharges are charged by the third party electricity provider in response to any increased costs of natural gas consumed to generate the electricity. These increased costs could reduce the Trust's share of 2019 net proceeds below the level that would exist if such costs remained at the level experienced in 2018. Similarly, new or changes to existing laws or regulations with which the Underlying Properties must comply, including environmental regulations or regulation of injection and disposal wells in connection with concerns regarding seismic activity, could result in increased production or development costs. If production and development costs attributable to the Royalties exceed the gross proceeds related to production from the Underlying Properties, the Trust will not receive net proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest during the deficit period. Development activities may not generate sufficient additional proceeds to repay the costs.

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

The value of the Units will depend upon, among other things, the reserves attributable to the Royalties from the Underlying Properties. The calculations of proved reserves and estimating reserves is inherently uncertain. In addition, the estimates of future net revenues are based upon various assumptions regarding future production levels, prices and costs that may prove to be incorrect over time.

The accuracy of any reserve estimate is a function of the quality of available data, engineering interpretation and judgment and the assumptions used regarding the quantities of recoverable crude oil and natural gas and the future prices of crude oil and natural gas. Petroleum engineers consider many factors and make many assumptions in estimating reserves. Those factors and assumptions include:

historical production from the area compared with production rates from similar producing areas;

the effects of governmental regulation;

assumptions about future commodity prices, production and development costs, taxes, and capital expenditures;

the availability of enhanced recovery techniques; and

relationships with landowners, working interest partners, pipeline companies and others. Changes in any of these factors and assumptions can materially change reserve and future net revenue estimates. The Trust's estimate of reserves and future net revenues is further complicated because the Trust holds an interest in net overriding royalties and does not own a specific percentage of the crude oil or natural gas reserves. Ultimately, actual production, revenues and expenditures for the Underlying Properties, and therefore actual net proceeds payable to the Trust, will vary from estimates and those variations could be material. Results of drilling, testing and production after the date of those estimates may require substantial downward revisions or write-downs of reserves.

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The assets of the Trust are depleting assets and, if BROG and the other operators developing the Underlying Properties do not perform additional development projects, the assets may deplete faster than expected. Eventually, the assets of the Trust will cease to produce in commercial quantities and the Trust will cease to receive proceeds from such assets. In addition, a reduction in depletion tax benefits may reduce the market value of the Units.

The net proceeds payable to the Trust are derived from the sale of depleting assets. The reduction in proved reserve quantities is a common measure of depletion. Future maintenance and development projects on the Underlying Properties will affect the quantity of proved reserves and can offset the reduction in proved reserves. The timing and size of these projects will depend on the market prices of crude oil and natural gas. If the operators developing the Underlying Properties, including BROG, do not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust.

Because the net proceeds payable to the Trust are derived from the sale of depleting assets, the portion of distributions to Unit holders attributable to depletion may be considered a return of capital as opposed to a return on investment. Distributions that are a return of capital will ultimately diminish the depletion tax benefits available to the Unit holders, which could reduce the market value of the Units over time. Eventually, the Royalties will cease to produce in commercial quantities and the Trust will, therefore, cease to receive any distributions of net proceeds therefrom.

Future royalty income may be subject to risks relating to the creditworthiness of third parties.

The Trust does not lend money and has limited ability to borrow money, which the Trustee believes limits the Trust's risk from credit markets. The Trust's future royalty income, however, may be subject to risks relating to the creditworthiness of the operators of the Underlying Properties and other purchasers of the crude oil and natural gas produced from the Underlying Properties, as well as risks associated with fluctuations in the price of crude oil and natural gas.

The market price for the Units may not reflect the value of the royalty interests held by the Trust.

The public trading price for the Units tends to be tied to the recent and expected levels of cash distribution on the Units. The amounts available for distribution by the Trust vary in response to numerous factors outside the control of the Trust, including prevailing prices for crude oil and natural gas produced from the Royalties. The market price is not necessarily indicative of the value that the Trust would realize if it sold those Royalties to a third party buyer. In addition, such market price is not necessarily reflective of the fact that since the assets of the Trust are depleting assets, a portion of each cash distribution paid on the Units should be considered by investors as a return of capital, with the remainder being considered as a return on investment. There is no guarantee that distributions made to a Unit holder over the life of these depleting assets will equal or exceed the purchase price paid by the Unit holder.

Operational risks and hazards associated with the development of the Underlying Properties may decrease Trust distributions.

There are operational risks and hazards associated with the production and transportation of crude oil and natural gas, including without limitation natural disasters, blowouts, explosions, fires, leakage of crude oil or natural gas, releases of other hazardous materials, mechanical failures, cratering, and pollution. Any of these or similar occurrences could result in the interruption or cessation of operations, personal injury or loss of life, property damage, damage to productive formations or equipment, or damage to the environment or natural resources, or cleanup obligations. The operation of oil and gas properties is also subject to various laws and regulations. Non-compliance with such laws and regulations could subject the operator to additional costs, sanctions or liabilities. The uninsured costs resulting from

any of these or similar occurrences could be deducted as a cost of production in calculating the net proceeds payable to the Trust and would therefore reduce Trust distributions by the amount of such uninsured costs.

As oil and gas production from the Waddell Ranch properties is processed through a single facility, future distributions from those properties may be particularly susceptible to such risks. A partial or complete shut down of

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operations at that facility could disrupt the flow of royalty payments to the Trust and, accordingly, the Trust's distributions to its Unit holders. In addition, although BROG is the operator of record of the properties burdened by the Waddell Ranch overriding royalty interests, none of the Trustee, the Unit holders or BROG has an operating interest in the properties burdened by the Texas Royalty properties (as defined herein on page 8) overriding royalty interests. As a result, these parties are not in a position to eliminate or mitigate the above or similar occurrences with respect to such properties and may not become aware of such occurrences prior to any reduction in Trust distributions which may result therefrom.

Terrorism and continued hostilities in the Middle East could decrease Trust distributions or the market price of the Units.

Terrorist attacks and the threat of terrorist attacks, whether domestic or foreign, as well as the military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism and sustained military campaigns could adversely affect Trust distributions or the market price of the Units in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in crude oil and natural gas prices, or the possibility that the infrastructure on which the operators developing the Underlying Properties rely could be a direct target or an indirect casualty of an act of terror.

Unit holders and the Trustee have no influence over the operations on, or future development of, the Underlying Properties.

Neither the Trustee nor the Unit holders can influence or control the operations on, or future development of, the Underlying Properties. The failure of an operator to conduct its operations, discharge its obligations, deal with regulatory agencies or comply with laws, rules and regulations, including environmental laws and regulations, in a proper manner could have an adverse effect on the net proceeds payable to the Trust. The current operators developing the Underlying Properties are under no obligation to continue operations on the Underlying Properties. Neither the Trustee nor the Unit holders have the right to replace an operator.

The operators developing the Texas Royalty properties have no duty to protect the interests of the Unit holders and do not have sole discretion regarding development activities on the Underlying Properties.

Under the terms of a typical operating agreement relating to oil and gas properties, the operator owes a duty to working interest owners to conduct its operations on the properties in a good and workmanlike manner and in accordance with its best judgment of what a prudent operator would do under the same or similar circumstances. BROG is the operator of record of the Waddell Ranch overriding royalty interests and in such capacity owes the Trust a contractual duty under the conveyance agreement for that overriding royalty interest to operate the Waddell Ranch properties in good faith and in accordance with a prudent operator standard. The operators of the properties burdened by the Texas Royalty properties overriding royalty interests, however, have no contractual or fiduciary duty to protect the interests of the Trust or the Unit holders other than indirectly through its duty of prudent operations to the unaffiliated owners of the working interests in those properties.

In addition, even if an operator, including BROG in the case of the Waddell Ranch properties (as defined herein on page 8), concludes that a particular development operation is prudent on a property, it may be unable to undertake such activity unless it is approved by the requisite approval of the working interest owners of such properties (typically the owners of at least a majority of the working interests). Even if the Trust concludes that such activities in respect of any of its overriding royalty interests would be in its best interests, it has no right to cause those activities to be undertaken.

The operator developing any Underlying Property may transfer its interest in the property without the consent of the Trust or the Unit holders.

Any operator developing any of the Underlying Properties may at any time transfer all or part of its interest in the Underlying Properties to another party. Neither the Trust nor the Unit holders are entitled to vote on any transfer of the

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properties underlying the Royalties, and the Trust will not receive any proceeds of any such transfer. Following any transfer, the transferred property will continue to be subject to the Royalties, but the net proceeds from the transferred property will be calculated separately and paid by the transferee. The transferee will be responsible for all of the transferor's obligations relating to calculating, reporting and paying to the Trust the Royalties from the transferred property, and the transferor will have no continuing obligation to the Trust for that property.

The operator developing any Underlying Property may abandon the property, thereby terminating the Royalties payable to the Trust.

The operators developing the Underlying Properties, or any transferee thereof, may abandon any well or property without the consent of the Trust or the Unit holders if they reasonably believe that the well or property can no longer produce in commercially economic quantities. This could result in the termination of the Royalties relating to the abandoned well or property.

The Royalties can be sold and the Trust would be terminated.

The Trustee must sell the Royalties if the holders of 75% or more of the Units approve the sale or vote to terminate the Trust. The Trustee must also sell the Royalties if they fail to generate net revenue for the Trust of at least \$1,000,000 per year over any consecutive two-year period. Sale of all of the Royalties will terminate the Trust. The net proceeds of any sale will be distributed to the Unit holders. The sale of the remaining Royalties and the termination of the Trust will be taxable events to the Unit holders. Generally, a Unit holder will realize gain or loss equal to the difference between the amount realized on the sale and termination of the Trust and his adjusted basis in such Units. Gain or loss realized by a Unit holder who is not a dealer with respect to such Units and who has a holding period for the Units of more than one year will be treated as long-term capital gain or loss except to the extent of any depletion recapture amount, which must be treated as ordinary income. Other federal and state tax issues concerning the Trust are discussed under Note 4 and Note 7 to the Trust's financial statements, which are included herein. Each Unit holder should consult his own tax advisor regarding Trust tax compliance matters, including federal and state tax implications concerning the sale of the Royalties and the termination of the Trust.

Unit holders have limited voting rights and have limited ability to enforce the Trust's rights against the current or future operators developing the Underlying Properties.

The voting rights of a Unit holder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Unit holders or for an annual or other periodic re-election of the Trustee.

The Trust indenture and related trust law permit the Trustee and the Trust to sue BROG, Riverhill Energy Corporation or any other future operators developing the Underlying Properties to compel them to fulfill the terms of the conveyance of the Royalties. If the Trustee does not take appropriate action to enforce provisions of the conveyance, the recourse of the Unit holders would likely be limited to bringing a lawsuit against the Trustee to compel the Trustee to take specified actions. Unit holders probably would not be able to sue BROG, Riverhill Energy Corporation or any other future operators developing the Underlying Properties.

Financial information of the Trust is not prepared in accordance with GAAP.

The financial statements of the Trust are prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States, or GAAP. Although this basis of accounting is permitted for royalty trusts by the U.S. Securities and Exchange Commission (SEC), the

financial statements of the Trust differ from GAAP financial statements because revenues are not accrued in the month of production and cash reserves may be established for specified contingencies and deducted which could not be accrued in GAAP financial statements.

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The limited liability of the Unit holders is uncertain.

The Unit holders are not protected from the liabilities of the Trust to the same extent that a shareholder would be protected from a corporation's liabilities. The structure of the Trust does not include the interposition of a limited liability entity such as a corporation or limited partnership which would provide further limited liability protection to Unit holders. While the Trustee is liable for any excess liabilities incurred if the Trustee fails to insure that such liabilities are to be satisfied only out of Trust assets, under the laws of Texas, which are unsettled on this point, a holder of Units may be jointly and severally liable for any liability of the Trust if the satisfaction of such liability was not contractually limited to the assets of the Trust and the assets of the Trust and the Trustee are not adequate to satisfy such liability. As a result, Unit holders may be exposed to personal liability.

The tax treatment of an investment in Trust Units could be affected by recent and potential legislative changes, possibly on a retroactive basis.

U.S. federal tax reform legislation informally known as the Tax Cuts and Jobs Act (the TCJA) was enacted December 22, 2017, and makes significant changes to the federal income tax rules applicable to both individuals and entities, including changes to the effective tax rate on a Unit holder's allocable share of certain income from the Trust. The TCJA is complex and lacks administrative guidance, thus, Unit holders should consult their tax advisor regarding the TCJA and its effect on an investment in Trust Units.

For taxable years beginning after 2017, the highest marginal U.S. federal income tax rates applicable to ordinary income and long-term capital gains of individuals are 37% and 20%, respectively. Any modification to the U.S. federal income tax laws or interpretations thereof (including administrative guidance relating to the TCJA) may be applied retroactively and could adversely affect our business, financial condition or results of operations. The Trust is unable to predict whether any changes or other proposals will ultimately be enacted, or whether any adverse interpretations will be used. Any such changes or interpretations could negatively impact the value of an investment in the Trust Units.

Item 1B. *Unresolved Staff Comments*

The Trust has not received any written comments from the Securities and Exchange Commission staff regarding its periodic or current reports under the Act not less than 180 days before December 31, 2018, which comments remain unresolved.

Item 2. *Properties*

The net overriding royalties conveyed to the Trust (the Royalties) include: (1) a 75% net overriding royalty carved out of Southland Royalty's fee mineral interests in the Waddell Ranch in Crane County, Texas (the Waddell Ranch properties); and (2) a 95% net overriding royalty carved out of Southland Royalty's major producing royalty interests in Texas (the Texas Royalty properties). The interests out of which the Trust's net overriding royalty interests were carved were in all cases less than 100%. The Trust's net overriding royalty interests represent burdens against the properties in favor of the Trust without regard to ownership of the properties from which the overriding royalty interests were carved. The net overriding royalty for the Texas Royalty properties is subject to the provisions of the lease agreements under which such royalties were created. References below to net wells and acres are to the interests of BROG (from which the Royalties were carved) in the gross wells and acres.

A production index for oil and gas properties is the number of years derived by dividing remaining reserves by current production. The production index for the Trust properties based on the reserve report prepared by independent petroleum engineers as of December 31, 2018, is approximately 7.6 years.

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The following information under this Item 2 is based upon data and information, including audited computation statements, furnished to the Trustee by BROG and Riverhill Energy.

PRODUCING ACREAGE, WELLS AND DRILLING

Waddell Ranch Properties. The net profits/overriding royalty interest in the Waddell Ranch properties is the largest asset of the Trust. The mineral interests in the Waddell Ranch, from which such net royalty interests are carved, vary from 37.5% (Trust net interest) to 50% (Trust net interest) in 78,715 gross (34,205 net) producing acres. A majority of the proved reserves are attributable to six fields: Dune, Sand Hills (Judkins), Sand Hills (McKnight), Sand Hills (Tubb), University-Waddell (Devonian) and Waddell. At December 31, 2018, the Waddell Ranch properties contained 791 gross (349 net) productive oil wells, 141 gross (117 net) productive gas wells and 242 gross (121 net) injection wells.

BROG is operator of record of the Waddell Ranch properties. All field, technical and accounting operations have been contracted by agreements between the working interest owners and Schlumberger Integrated Project Management (IPM) and Riverhill Capital Corporation (Riverhill Capital), but remain under the direction of BROG.

Six major fields on the Waddell Ranch properties account for more than 80% of the total production. In the six fields, there are 12 producing zones ranging in depth from 2,800 to 10,600 feet. Most prolific of these zones are the Grayburg and San Andres, which produce from depths between 2,800 and 3,400 feet. Also productive from the San Andres are the Sand Hills (Judkins) gas field and the Sand Hills (McKnight) oil field, the Dune (Grayburg/San Andres) oil field, and the Waddell (Grayburg/San Andres) oil field.

The Dune and Waddell oil fields are productive from both the Grayburg and San Andres formations. The Sand Hills (Tubb) oil fields produce from the Tubb formation at depths averaging 4,300 feet, and the University Waddell (Devonian) oil field is productive from the Devonian formation between 8,400 and 9,200 feet.

The Waddell Ranch properties are mature producing properties, and all of the major oil fields are currently being waterflooded for the purpose of facilitating enhanced recovery. Proved reserves and estimated future net revenues attributable to the properties are included in the reserve reports summarized below. BROG does not own the full working interest in any of the tracts constituting the Waddell Ranch properties and, therefore, implementation of any development programs will require approvals of other working interest holders as well as BROG. In addition, implementation of any development programs will be dependent upon oil and gas prices currently being received and anticipated to be received in the future. There were 0 gross (0 net) drill wells completed on the Waddell Ranch properties during 2018. At December 31, 2018, there were 1 drill wells and 1 workover in progress on the Waddell Ranch properties. There were 0 gross (0 net) drill wells completed on the Waddell Ranch properties during 2017. At December 31, 2017, there were 0 drill wells and 1 workover in progress on the Waddell Ranch properties. There were 0 gross (0 net) drill wells completed on the Waddell Ranch properties during 2016. At December 31, 2015, there were 0 drill wells and 1 workovers in progress on the Waddell Ranch properties.

BROG has advised the Trustee that the total amount of capital expenditures for 2018 with regard to the Waddell Ranch properties totaled \$4.3 million (gross). Capital expenditures include the cost of remedial and maintenance activities. The amount spent is approximately \$1.7 million of the budgeted amount projected by BROG for 2018.

BROG has advised the Trustee that the capital expenditures budget for 2019 totals approximately \$6.6 million (gross) (\$2.9 million net to the Trust), of which approximately \$4.2 million (gross) is attributable to facilities. The remaining \$2.4 million would be attributable to remedial work and the completion of 2 new drill wells. Accordingly, there is a 380% increase in capital expenditures for 2019 as compared with the 2018 capital expenditures. The major reason for

the variance is the increased prices. There will be 2 new drill wells and 0 recompletions in 2019 as compared to 0 new drill wells and 2 recompletion in 2018.

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Texas Royalty Properties. The Texas Royalty properties consist of royalty interests in mature producing oil fields, such as Yates, Wasson, Sand Hills, East Texas, Kelly-Snyder, Panhandle Regular, N. Cowden, Todd, Keystone, Kermit, McElroy, Howard-Glasscock, Seminole and others located in 33 counties across Texas. The Texas Royalty properties consist of approximately 125 separate royalty interests containing approximately 303,000 gross (approximately 51,000 net) producing acres. Approximately 41% of the future net revenues discounted at 10% attributable to Texas Royalty properties are located in the Wasson and Yates fields. Detailed information concerning the number of wells on royalty properties is not generally available to the owners of royalty interests. Consequently, an accurate count of the number of wells located on the Texas Royalty properties cannot readily be obtained.

In February 1997, BROG sold its interests in the Texas Royalty properties that are subject to the Net Overriding Royalty Conveyance to the Trust dated effective November 1, 1980 (Texas Royalty Conveyance) to Riverhill Energy Corporation (Riverhill Energy), which was then a wholly-owned subsidiary of Riverhill Capital and an affiliate of Coastal Management Corporation (CMC). At the time of such sale, Riverhill Capital was a privately owned Texas corporation with offices in Bryan and Midland, Texas. The Trustee was informed by BROG that, as required by the Texas Royalty Conveyance, Riverhill Energy succeeded to all of the requirements upon, and the responsibilities of BROG under, the Texas Royalty Conveyance with regard to the Texas Royalty properties. BROG and Riverhill Energy further advised the Trustee that all accounting operations pertaining to the Texas Royalty properties were being performed by Riverhill Energy.

The Trustee has been advised that, effective April 1, 1998, Schlumberger Technology Corporation (STC) acquired all of the shares of stock of Riverhill Capital. Prior to the acquisition by STC, CMC and Riverhill Energy were wholly-owned subsidiaries of Riverhill Capital. The Trustee has further been advised, in accordance with the STC acquisition of Riverhill Capital, the shareholders of Riverhill Capital acquired ownership of all shares of stock of Riverhill Energy. Effective January 1, 2001 CMC merged into STC. Thus, the ownership in the Texas Royalty properties remained in Riverhill Energy.

The Trustee has been advised that as of May 1, 2000, the accounting operations pertaining to the Texas Royalty properties were transferred from STC to Riverhill Energy. As of January 1, 2012, ConocoPhillips assumed all field, technical and accounting operations, on behalf of BROG, with regard to the Waddell Ranch properties. ConocoPhillips currently provides summary reporting of monthly results for the Waddell Ranch properties.

Well Count and Acreage Summary. The following table shows as of December 31, 2018, the gross and net producing wells and acres for the BROG interests on the Waddell Ranch. The net wells and acres are determined by multiplying the gross wells or acres by the BROG interests owner's working interest in the wells or acres. Similar information is not available for the Riverhill Energy interests. There is no undeveloped acreage on the Waddell Ranch properties.

	Number of Wells		Acres	
	Gross	Net	Gross	Net
BROG Interests	1,769	884	77,000	37,300

Table of Contents**OIL AND GAS PRODUCTION**

The Trust recognizes production during the month in which the related distribution is received. Production of oil and gas attributable to the Royalties and the Underlying Properties, the related average sales prices and the average production cost per unit of production attributable to the Underlying Properties for the three years ended December 31, 2018, excluding portions attributable to the adjustments discussed below, were as follows:

	Waddell Ranch Properties			Texas Royalty Properties			Total		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Royalties:									
Production									
Oil (barrels)	228,277	289,349	209,777	239,196	255,680	280,654	467,473	545,029	490,431
Gas (Mcf)	1,343,148	1,699,525	1,250,235	252,851	285,453	340,446	1,595,999	1,984,978	1,590,681
Underlying Properties:									
Production									
Oil (barrels)	628,228	688,851	570,580	266,324	282,390	300,710	894,552	971,241	871,290
Gas (Mcf)	3,678,665	3,978,339	3,402,004	281,442	315,206	362,918	3,960,107	4,293,545	3,764,922
Average Sales Price									
Oil/barrel	\$ 58.22	\$ 46.35	\$ 40.81	\$ 58.44	\$ 45.80	\$ 34.55	\$ 58.11	\$ 45.88	\$ 39.73
Gas/Mcf	\$ 3.32	\$ 3.12	\$ 2.17	\$ 6.58	\$ 5.22	\$ 3.33	\$ 3.55	\$ 3.28	\$ 2.29
Average Production Cost									
Oil/Gas BOE	\$ 20.30	\$ 13.38	\$ 6.79	\$ 5.18	\$ 3.48	\$ 8.73	\$ 17.26	\$ 11.41	\$ 12.94

Since the oil and gas sales attributable to the Royalties are based on an allocation formula that is dependent on such factors as price and cost (including capital expenditures), production amounts do not necessarily provide a meaningful comparison.

Waddell Ranch properties lease operating expense for 2018 was \$23.1 million (gross). The lease operating expense increased from \$16,402,257 in 2017 primarily because of increasing activity and facilities maintenance. Waddell Ranch lifting cost on a barrel of oil equivalent (BOE) basis was \$20.30/bbl as compared to \$13.38 in 2017 and \$6.79 in 2016.

PRICING INFORMATION

Reference is made to the caption entitled Regulation for information as to federal regulation of prices of natural gas. The following paragraphs provide information regarding sales of oil and gas from the Waddell Ranch properties. As a royalty owner, Riverhill Energy is not furnished detailed information regarding sales of oil and gas from the Texas Royalty properties.

Oil. The Trustee has been advised by BROG that since June 2006, the oil from the Waddell Ranch has been marketed by ConocoPhillips by soliciting bids from third parties on an outright sale basis of production listed in bid packages.

Gas. The gas produced from the Waddell Ranch properties is processed through a natural gas processing plant and sold at the tailgate of the plant. Plant products are marketed by Burlington Resources Trading Inc., an indirect subsidiary of BRI. The processor of the gas (Warren Petroleum Company, L.P.) receives 15% of the liquids and residue gas as a fee for gathering, compression, treating and processing the gas.

OIL AND GAS RESERVES

The following are definitions adopted by the SEC and the Financial Accounting Standards Board which are applicable to terms used within this Item:

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

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known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

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

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.

Estimated future net revenues are computed by applying 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 to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet

presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, and assuming continuation of existing economic conditions. Estimated future net revenues are sometimes referred to herein as estimated future net cash flows.

Present value of estimated future net revenues is computed using the estimated future net revenues and a discount factor of 10%.

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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.

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 17 CFR 210.4-10(a)(2), or by other evidence using reliable technology establishing reasonable certainty.

The process of estimating oil and gas reserves is complex and requires significant judgment. As a result, the Trustee has developed internal policies and controls for estimating reserves. As described above, the Trust does not have information that would be available to a company with oil and gas operations because detailed information is not generally available to owners of royalty interests. The Trustee gathers production information (which information is net to the Trust's interests in the Underlying Properties) and provides such information to Cawley, Gillespie & Associates, Inc., who extrapolates from such information estimates of the reserves attributable to the Underlying Properties based on its expertise in the oil and gas fields where the Underlying Properties are situated, as well as publicly available information. The Trust's policies regarding reserve estimates require proved reserves to be in compliance with the SEC definitions and guidance.

The independent petroleum engineers' reports as to the proved oil and gas reserves attributable to the Royalties conveyed to the Trust were obtained from Cawley, Gillespie & Associates, Inc. Cawley, Gillespie & Associates, Inc. has been in business since 1973 when the petroleum consulting firm Keller & Augustson merged with the petroleum consulting firm Cawley, Harrington & Gillespie. The primary business of Cawley, Gillespie & Associates, Inc. is the estimation and evaluation of petroleum reserves. Kenneth J. Mueller, has been employed by Cawley, Gillespie & Associates, Inc. since 1996. Mr. Mueller attended Texas A&M University from 1975 to 1979, graduating with a Bachelor of Science degree, Summa Cum Laude, in Petroleum Engineering in 1979, and has in excess of nineteen years experience in oil and gas reserves studies and evaluations. Mr. Mueller is a licensed professional engineer with the Texas Board of Professional Engineers and a member of the Texas Society of Professional Engineers.

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Cawley, Gillespie & Associates, Inc.'s reports are attached as exhibits to this Form 10-K. The following table presents a reconciliation of proved reserve quantities from January 1, 2016 through December 31, 2018 (in thousands):

	Waddell Ranch Properties		Texas Royalty Properties		Total	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
January 1, 2016	1,438	6,556	3,172	2,490	4,610	9,046
Extensions, discoveries, and other additions	85	152			85	152
Revisions of previous estimates	(14)	485	178	33	164	518
Production	(152)	(893)	(252)	(305)	(404)	(1,198)
December 31, 2016	1,357	6,300	3,098	2,218	4,455	8,518
Extensions, discoveries, and other additions	31	649			31	649
Revisions of previous estimates	529	3,243	136	77	665	3,320
Production	(289)	(1700)	(256)	(285)	(545)	(1,985)
December 31, 2017	1,628	8,492	2,978	2,010	4,606	10,502
Extensions, discoveries, and other additions	46	109			46	109
Revisions of previous estimates	(367)	(1,523)	445	425	78	(1,098)
Production	(230)	(1,356)	(239)	(253)	(469)	(1,609)
December 31, 2018	1,077	5,722	3,184	2,182	4,261	7,904

Estimated quantities of proved reserves and net cash flow as of December 31, 2018 are as follows:

	Waddell Ranch Properties		Net Cash Flow, M\$	10% Disc. Cash Flow, M\$
	Oil (Mstb)	Gas (Mcf)		
Proved Developed Producing	1,031	5,613	\$ 75,475	\$ 53,090
Proved Developed Non-Producing	25	58	\$ 1,554	\$ 364
Proved Developed	1,056	5,671	\$ 77,029	\$ 53,454
Proved Undeveloped	21	51	1,318	630
Total Proved	1,077	5,722	\$ 78,347	\$ 54,084

	Texas Royalty Properties		Net Cash Flow,	10% Disc. Cash Flow,
	Oil (Mstb)	Gas (Mcf)		

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			M\$	M\$
Proved Developed Producing	3,184	2,182	\$ 192,115	\$ 85,142
Proved Developed	3,184	2,182	\$ 192,115	\$ 85,142
Total Proved	3,184	2,182	\$ 192,115	\$ 85,142

**Total Waddell Ranch Plus Texas Royalty
Properties**

	Oil (Mstb)	Gas (Mcf)	Net Cash Flow, M\$	10% Disc. Cash Flow, M\$
Proved Developed Producing	4,215	7,795	\$ 267,590	\$ 183,232
Proved Developed Non-Producing	25	58	\$ 1,554	\$ 364
Proved Developed	4,240	7,853	\$ 269,144	\$ 138,596
Proved Undeveloped	21	51	1,318	630
Total Proved	4,261	7,904	\$ 270,462	\$ 139,226

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Estimated quantities of proved developed reserves of oil and gas as of the dates indicated were as follows (in thousands):

	Oil (Barrels)	Gas (Mcf)
Proved Developed Reserves:		
January 1, 2016	4,610	9,046
December 31, 2016	4,455	8,578
December 31, 2017	4,606	10,502
December 31, 2018	4,261	7,904

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 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 gas reserves.

Estimates of proved oil and gas reserves are by their very nature imprecise. Estimates of future net revenue attributable to proved reserves are sensitive to the unpredictable prices of oil and gas and other variables.

The 2018, 2017 and 2016 change in the standardized measure of discounted future net cash revenues related to future royalty income from proved reserves attributable to the Royalties discounted at 10% is as follows (in thousands):

	Waddell Ranch Properties			Texas Royalty Properties			Total		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
January 1	\$ 64,682	\$ 42,332	\$ 55,321	\$ 65,228	\$ 55,745	\$ 70,784	\$ 129,910	\$ 98,077	\$ 126,105
Extensions, discoveries, and other additions	994	2,093	1,347				994	2,093	1,347
Accretion of discount	6,468	4,233	5,532	6,523	5,575	7,078	12,991	9,808	12,610
Revisions of previous estimates and other	(843)	33,845	(9,081)	28,404	16,646	(11,817)	27,561	50,491	(20,898)
Royalty income	(17,025)	(17,821)	(10,787)	(15,013)	(12,738)	(10,300)	(32,038)	(30,559)	(21,087)
December 31	\$ 54,276	\$ 64,682	\$ 42,332	\$ 85,142	\$ 65,228	\$ 55,745	\$ 139,418	\$ 129,910	\$ 98,077

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Average oil and gas prices of \$65.56 per barrel and \$3.112 per Mcf were used to determine the estimated future net revenues from the Waddell Ranch properties and the Texas Royalty properties, respectively, at December 31, 2018. The upward revisions of both reserves and discounted future net cash flows for the Waddell Ranch properties are primarily due to stronger pricing for oil and gas. The Texas Royalty Properties are revised upward due to stronger pricing for oil and gas.

Average oil and gas prices of \$51.34 per barrel and \$2.97 per Mcf were used to determine the estimated future net revenues from the Waddell Ranch properties and the Texas Royalty properties, respectively, at December 31, 2017. The upward revisions of both reserves and discounted future net cash flows for the Waddell Ranch properties are primarily due to stronger pricing for oil offset by stronger gas pricing. The Texas Royalty Properties are revised downward due to stronger pricing for oil.

Average oil and gas prices of \$42.75 per barrel and \$2.46 per Mcf were used to determine the estimated future net revenues from the Waddell Ranch properties and the Texas Royalty properties, respectively, at December 31, 2016. The downward revisions of both reserves and discounted future net cash flows for the Waddell Ranch properties are primarily due to weaker pricing for oil offset by stronger gas pricing. The Texas Royalty Properties are revised downward due to weaker pricing for oil.

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The following presents estimated future net revenue and the present value of estimated future net revenue attributable to the Royalties, for each of the years ended December 31, 2018, 2017 and 2016 (in thousands):

	2018		2017		2016	
	Estimated Future Net Revenue	Present Value at 10%	Estimated Future Net Revenue	Present Value at 10%	Estimated Future Net Revenue	Present Value at 10%
Total Proved						
Waddell Ranch properties	\$ 78,347	\$ 54,084	\$ 99,438	\$ 64,682	\$ 64,167	\$ 42,332
Texas Royalty properties	192,115	85,142	146,133	65,228	124,102	55,745
Total	\$ 270,462	\$ 139,226	\$ 245,571	\$ 129,910	\$ 188,269	\$ 98,077

Reserve quantities and revenues shown in the preceding tables for the Royalties were estimated from projections of reserves and revenue attributable to the combined BROG, River Hill Energy and Trust interests in the Waddell Ranch properties and Texas Royalty properties. Reserve quantities attributable to the Royalties were estimated by allocating to the Royalties a portion of the total estimated net reserve quantities of the interests, based upon gross revenue less production taxes. Because the reserve quantities attributable to the Royalties are estimated using an allocation of the reserves, any changes in prices or costs will result in changes in the estimated reserve quantities allocated to the Royalties. Therefore, the reserve quantities estimated will vary if different future price and cost assumptions occur.

Proved reserve quantities are estimates based on information available at the time of preparation and such estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production of those reserves may be substantially different from the original estimate. Moreover, the present values shown above should not be considered as the market values of such oil and gas reserves or the costs that would be incurred to acquire equivalent reserves. A market value determination would include many additional factors.

Detailed information concerning the number of wells on royalty properties is not generally available to the owner of royalty interests. Consequently, the Registrant does not have information that would be disclosed by a company with oil and gas operations, such as an accurate account of the number of wells located on the above royalty properties, the number of exploratory or development wells drilled on the above royalty properties during the periods presented by this report, or the number of wells in process or other present activities on the above royalty properties, and the Registrant cannot readily obtain such information.

REGULATION

Many aspects of the production, pricing, transportation and marketing of crude oil and natural gas are regulated by federal and state agencies. Legislation affecting the oil and gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden on affected members of the industry.

Exploration and production operations are subject to various types of regulation at the federal, tribal, state and local levels. Such regulation includes requiring permits for the drilling and production of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, controlling and remediating pollution from exploration and production activities, proper handling and disposal of waste generated from exploration and production operations, the surface use and restoration of properties upon

which wells are drilled and the plugging and abandonment of wells. Natural gas and oil operations are also subject to various conservation laws and regulations that regulate the size of drilling and spacing units or proration units and the density of wells which may be drilled and unitization or pooling of oil and gas properties. In addition, state conservation laws establish maximum allowable production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratable production. The effect of these regulations is to limit the amounts of natural gas and oil that can be produced, potentially to raise prices, and to limit the number of wells or the locations which can be drilled.

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Federal Natural Gas Regulation

The Federal Energy Regulatory Commission (the FERC) is primarily responsible for federal regulation of natural gas. The interstate transportation and sale for resale of natural gas is subject to federal governmental regulation, including regulation of transportation and storage tariffs and various other matters, by the FERC. On August 8, 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, to direct the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and to significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or the FERC rules, regulations or orders thereunder. Wellhead sales of domestic natural gas are not subject to regulation. Consequently, sales of natural gas may be made at market prices, subject to applicable contract provisions.

Sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. Several major regulatory changes have been implemented by Congress and the FERC from 1985 to the present that affect the economics of natural gas production, transportation, and sales. In addition, the FERC continues to promulgate revisions to various aspects of the rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to the FERC's jurisdiction. These initiatives may also affect the intrastate transportation of gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation of the natural gas industry. The ultimate impact of the rules and regulations issued by the FERC since 1985 cannot be predicted. In addition, many aspects of these regulatory developments have not become final but are still pending judicial decisions and final decisions by the FERC.

New proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, the FERC, state regulatory bodies and the courts. The Trust cannot predict when or if any such proposals might become effective, or their effect, if any, on the Trust. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue.

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. Crude oil prices are affected by a variety of factors. Since domestic crude price controls were lifted in 1981, the principal factors influencing the prices received by producers of domestic crude oil have been the pricing and production of the members of the Organization of Petroleum Export Countries (OPEC).

On December 19, 2007, President Bush signed into law the Energy Independence & Security Act of 2007 (PL 110 140). The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations, and establishes penalties for violations thereunder.

State Regulation

The various states regulate the production and sale of oil and natural gas, including imposing requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rates of production may be regulated and the maximum daily production allowables from both oil and gas wells may be established on a market demand or conservation basis, or both.

Local Regulation

Drilling for and production and transportation of crude oil and natural gas are also regulated by local authorities. Local laws may include land use regulations, permitting requirements, and noise and traffic ordinances. Such regulation could increase drilling and production costs or create delays in development and production of the Underlying Properties.

Table of Contents**Environmental Regulation**

Companies in the oil and gas industry are subject to stringent and complex federal, tribal, state and local laws and regulations governing the health and safety aspects of oil and gas operations, the management and discharge of materials into the environment, or otherwise relating to environmental protection. Those laws and regulations may impose numerous obligations that are applicable to the operations of the Underlying Properties, including the acquisition of a permit before conducting drilling, production or underground injection activities; the restriction on the types, quantities and concentrations of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands, endangered or threatened species habitat, and other protected areas; the installation of emission monitoring and/or pollution control equipment; the reporting of the types and quantities of various substances that are stored, processed, or released in connection with operation of the Underlying Properties; the remediation of pollution from current or former operations, such as cleanup of releases, pit closure, removal of surface equipment and plugging of abandoned wells; the planning and preparedness for spill and emergency response activities; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from operations including waste generation, air emissions, water discharges and current and historical waste disposal practices. 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. Under certain environmental laws and regulations, the operators of the Underlying Properties could also be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination, in either case, whether at a drill site or a waste disposal facility, regardless of whether the operators were responsible for the release or contamination or if the operations were in compliance with all applicable laws at the time those actions were taken.

In addition, climate change is the subject of an important public policy debate and the basis for new legislation proposed by the United States Congress and certain states. Some states have adopted climate change statutes and regulations. The United States Environmental Protection Agency (the EPA) has promulgated greenhouse gas monitoring and reporting regulations that, since 2011, have required annual reporting of carbon dioxide, methane and nitrous oxide emissions from certain sources in the oil and natural gas industry sector, including in the onshore oil and natural gas production segment.

Beyond measuring and reporting, the EPA issued an Endangerment Finding under Section 202(a) of the Clean Air Act, concluding that greenhouse gas pollution threatens the public health and welfare of future generations. The EPA indicated that it will use data collected through the reporting rules to decide whether to promulgate future greenhouse gas emission limits. On August 16, 2012, the EPA issued a final rule that established new source performance standards for volatile organic compounds (VOC(s)) and sulfur dioxide, an air toxics standard for major sources of oil and natural gas production, and an air toxics standard for major sources of natural gas transmission and storage. The rule required that, starting January 1, 2015, all hydraulically fractured or refractured natural gas wells be completed using reduced emission (green) completion technology, which significantly reduces VOC emissions. Limiting emissions of VOCs will have the co-benefit of also limiting methane, a greenhouse gas. These regulations also apply to storage tanks and other equipment in the affected oil and natural gas industry segments. On May 12, 2016, the EPA issued a final rule establishing additional standards for the reduction of methane, VOCs, and other emissions from new and existing sources in the oil and gas sector. Among other requirements, these new standards require green completion technology for new hydraulically fractured or refractured oil wells. And rulemaking concerning regulation of greenhouse gas and other emissions from the oil and natural gas industry continues: in October 2018, the EPA released proposed revisions to some of the 2016 requirements, including reducing the required frequency of fugitive emissions monitoring at well sites and compressor stations. Accordingly, the ultimate scope of these regulations is uncertain.

Congress and various states, including Texas, have proposed or adopted legislation regulating or requiring disclosure of the chemicals in the hydraulic fracturing fluid that is used in the drilling operation. Texas requires oil and gas operators to disclose the chemicals on the Frac Focus website. Hydraulic fracturing has historically been regulated by state oil and natural gas commissions. The EPA, however, has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act (the SDWA). The EPA has issued

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permitting guidance for oil and natural gas hydraulic fracturing activities using diesel fuels. Under the guidance, EPA defined the term *diesel* to include five categories of oils, including some such as kerosene, that are not traditionally considered to be diesel.

The Federal Water Pollution Control Act, also known as the Clean Water Act (*CWA*), and analogous state laws impose restrictions and strict controls on the discharge of pollutants, including produced waters and other oil and natural gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or the relevant state agency. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. In May 2015, EPA and the U.S. Army Corps of Engineers jointly announced a final rule defining the *Waters of the United States* (*WOTUS*) which are protected under the CWA. The new rule, which would have made additional waters expressly *Waters of the United States* and therefore subject to the jurisdiction of the Clean Water Act, rather than subject to a case-specific evaluation, was stayed by the U.S. Court of Appeals for the Sixth Circuit before it took effect. On February 1, 2018, EPA officially delayed implementation of the 2015 rule until early 2020, and in July 2018, the EPA proposed repeal of the 2015 WOTUS rule. Later that year, EPA's decision was challenged in court, which resulted in a decision by the U.S. District Court for the District of South Carolina to enjoin EPA's February 2018 delay rule. Several states then acted to halt reinstatement of the 2015 WOTUS rule, the effect of all of which is that the 2015 WOTUS definition is currently in effect in 22 states. Meanwhile, in December 2018, the EPA and the U.S. Army Corps of Engineers issued a proposed rule to revise the definition of *Waters of the United States*. The proposed rule would narrow the definition, excluding, for example, streams that do not flow year-round and wetlands without a direct surface connection to other jurisdictional waters. Litigation by parties opposing the rule quickly followed. Due to the administrative procedures required to establish the rule and pending litigation, the new definition of *Waters of the United States* may not be implemented, if at all, for several years. Regardless, the applicable WOTUS definition affects what CWA permitting or other regulatory obligations may be triggered during development and operation of the Underlying Properties, and changes to the WOTUS definition could cause delays in development and/or increase the cost of development and operation of the Underlying Properties.

Spill prevention, control, and countermeasure (*SPCC*) regulations promulgated under the CWA and later amended by the Oil Pollution Act of 1990 impose obligations and liabilities related to the prevention of oil spills and damages resulting from such spills into or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities that store oil in more than threshold quantities, the release of which could reasonably be expected to reach jurisdictional waters, must develop, implement, and maintain SPCC Plans. 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.

The Comprehensive Environmental Response, Compensation and Liability Act (*CERCLA*), also known as the *superfund* law, imposes liability, regardless of fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a *hazardous substance* into the environment. These persons include the current or previous owner and operator of a site where a hazardous substance has been disposed and persons who disposed or arranged for the disposal of a hazardous substance at a site, or transported a hazardous substance to a site for disposal. CERCLA also authorizes the EPA and, in some cases, private parties to take actions in response to threats to the public health or the environment and to seek recovery from such responsible classes of persons of the costs of such an action. In the course of operations, the working interest owner and/or the operator of the Underlying Properties may have generated and may generate wastes that may fall within CERCLA's definition of *hazardous substances*. The operator of the Underlying Properties or the working interest owners may be responsible under CERCLA for all or part of the costs to clean up sites at which such substances have been disposed. Although the Trust is not the operator of any of the Underlying Properties, or the owner of any working interest, its ownership of royalty

interests could cause it to be responsible for all or part of such costs to the extent CERCLA imposes responsibility on such parties as owners.

The Underlying Properties have produced oil and/or gas for many years and, in connection with that production, managed waste, such as drilling fluids and produced water, that is subject to regulation under environmental laws. Although the Trust has no knowledge of the procedures followed by the operators of the Underlying Properties in this

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regard, hydrocarbons or other solid or hazardous wastes may have been or may be disposed or released on, under, or from the Underlying Properties by the current or previous operators or may have been disposed offsite of the Underlying Properties. Federal, state and local laws and regulations applicable to oil and gas-related wastes and properties have become increasingly more stringent. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties, the imposition of investigatory, ongoing monitoring, or remedial obligations, and/or the issuance of injunctions limiting or preventing some or all of the operations. Under these laws, removal or remediation of current releases of such materials or of previously disposed wastes or property contamination at a drill site or a waste disposal facility could be required by a governmental authority regardless of whether the operators of the Underlying Properties were responsible for the release or contamination or if the operations were in compliance with all applicable laws at the time those actions were taken.

The federal Safe Drinking Water Act (SDWA) and the Underground Injection Control (UIC) program promulgated under the SDWA and state programs regulate the drilling and operation of salt water disposal wells. EPA directly administers the UIC program in some states and in others administration is delegated to the state. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure that the disposed waters are not leaking into groundwater. In addition, because some states have become concerned that the injection or disposal of produced water could, under certain circumstances, trigger or contribute to earthquakes, they have adopted or are considering additional regulations regarding such disposal methods. Changes in regulations or the inability to obtain permits for new disposal wells in the future may affect the ability of the operators of the Underlying Properties to dispose of produced water and ultimately increase the cost of operation of the Underlying Properties or delay production schedules. For example, in 2014, the Railroad Commission of Texas (RRC) published a final rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the injected fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the RRC may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

In addition, several cases have recently put a spotlight on the issue of whether injection wells may be regulated under the CWA if a direct hydrological connection to a jurisdictional surface water can be established. The split among federal circuit courts of appeals that decided these cases engendered two petitions for writ of certiorari to the United States Supreme Court in August 2018, one of which was granted in February 2019. EPA has also brought attention to the reach of the CWA's jurisdiction in such instances by issuing a request for comment in February 2018 regarding the applicability of the CWA permitting program to discharges into groundwater with a direct hydrological connection to jurisdictional surface water, which hydrological connections should be considered direct, and whether such discharges would be better addressed through other federal or state programs. To date, no further action has been taken by EPA with respect to the issue, but should CWA permitting be required for saltwater injections wells, the costs of permitting and compliance for the Underlying Properties could increase.

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds and their habitat, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the CWA, and CERCLA. The United States Fish and Wildlife Service (USFWS) may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and private land use and could delay or prohibit land access or development. Where takings of, or harm to, species or damages to wetlands, habitat or natural resources occur or may occur, government entities or at times private parties may act to restrict or prevent oil and gas exploration or production activities or seek damages for harm to species, habitat or natural resources resulting from drilling or construction or production

activities, including, for example, for releases of oil, wastes, hazardous substances or other regulated materials, and may seek natural resources damages and, in some cases, criminal penalties.

The Underlying Properties and operation thereof may be subject to the requirements of the federal Occupational Safety and Health Act (OSHA) and comparable state statutes. The OSHA hazard communication standard, the EPA

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community right-to-know regulations under Title III of CERCLA, the general duty clause and Risk Management Planning regulations promulgated under section 112(r) of the Clean Air Act, and similar state statutes may require disclosure of information about hazardous materials used, produced or otherwise managed during operation of the Underlying Properties. These laws also require the development of risk management plans for certain facilities to prevent accidental releases of pollutants.

The Trustee is unable to predict the total impact of the current and potential regulations upon the operators of the Underlying Properties, but it is possible that the operators of the Underlying Properties could face operational delays, increases in the operating costs to comply with climate change or any other environmental legislation or regulation, or decreases in the completion of new oil and natural gas wells, each of which could reduce net proceeds payable to the Trust and Trust distributions.

Other Regulation

The petroleum industry is also subject to compliance with various other federal, tribal, state, and local regulations and laws, including, but not limited to, occupational safety, resource conservation and equal employment opportunity. The Trustee does not believe that compliance with these laws by the operating parties will have any material adverse effect on Unit holders.

Item 3. *Legal Proceedings*

There are no material pending legal proceedings to which the Trust is a party or of which any of its property is the subject.

Item 4. *Mine Safety Disclosures*

This Item is not applicable to the Trust.

Table of Contents**PART II****Item 5. Market for Units of the Trust, Related Security Holder Matters and Trust Purchases of Units of Beneficial Interest**

Units of Beneficial Interest (Units) of the Trust are traded on the New York Stock Exchange with the symbol PBT.

Approximately 913 Unit holders of record held the 46,608,796 Units of the Trust at December 31, 2018.

The Trust has no equity compensation plans and has not repurchased any Units during the period covered by this report.

Item 6. Selected Financial Data

	For the Year Ended December 31,				
	2018	2017	2016	2015	2014
Royalty income	\$ 32,088,282	\$ 30,559,527	\$ 21,087,908	\$ 17,795,462	\$ 49,010,648
Distributable income	\$ 30,789,460	\$ 29,325,416	\$ 19,348,835	\$ 16,049,702	\$ 47,717,493
Distributable income per Unit	\$.66	\$.63	\$ 0.42	\$ 0.34	\$ 1.02
Distributions per Unit	\$.66	\$.63	\$ 0.42	\$ 0.34	\$ 1.02
Total assets, December 31	\$ 3,994,193	\$ 3,950,462	\$ 4,398,723	\$ 2,145,443	\$ 2,828,267

Table of Contents**Computation of Royalty Income Received by the Trust**

The Trust's royalty income is computed as a percentage of the net profit from the operation of the properties in which the Trust owns net overriding royalty interests. The percentages of net profits are 75% and 95% in the cases of the Waddell Ranch properties and the Texas Royalty properties, respectively. Royalty income received by the Trust for the five years ended December 31, 2018, was computed as shown in the table on the next page.

	Year Ended December 31,							
	2018	2017		2016		2015		2014
	Texas Royalty Properties	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties
Waddell Ranch Properties	\$ 15,564,348	\$ 31,631,883	\$ 12,932,547	\$ 23,228,208	\$ 11,392,255	\$ 44,755,701	\$ 16,961,554	\$ 75,992,000
Texas Royalty Properties	1,851,682	12,007,971	1,644,306	7,317,646	1,334,290	14,226,102	2,133,924	21,629,000
		56,767				(732,097)		2,766,000
	17,416,030	43,696,621	14,576,853	30,545,854	12,726,645	58,249,076	19,095,478	100,388,000
	567,246	1,409,979	452,689	1,030,578	370,941	1,956,811	602,682	3,299,000
	83,054	273,048	75,623	338,599	61,814	586,809	110,141	1,084,000
				(349,817)		(656,236)		666,000
	962,975	16,402,257	639,920	12,980,419	1,451,483	26,438,272	1,947,322	29,375,000
		1,849,553		2,162,579		27,014,225		40,426,000
	\$ 1,613,275	\$ 19,934,837	\$ 1,168,232	\$ 16,162,358	\$ 1,884,238	\$ 55,339,881	\$ 2,660,145	74,851,000
	\$ 15,802,755	\$ 23,761,784	\$ 13,408,621	\$ 14,383,496	\$ 10,842,407	\$ 2,909,195	\$ 16,435,333	\$ 25,536,000
	75%	95%	75%	95%	75%	95%	75%	95%
	\$ 15,012,617	\$ 17,821,338	\$ 12,738,189	\$ 10,787,622	\$ 10,300,286	\$ 2,181,896	\$ 15,613,566	\$ 19,152,000

Table of Contents**Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation
Trustee's Discussion and Analysis for the Three-Year Period Ended December 31, 2018****Liquidity and Capital Resources**

As stipulated in the Trust Agreement, the Trust is intended to be passive in nature and the Trustee does not have any control over or any responsibility relating to the operation of the Underlying Properties. The Trustee has powers to collect and distribute proceeds received by the Trust and pay Trust liabilities and expenses and its actions have been limited to those activities. The Trust is a passive entity and other than the Trust's ability to periodically borrow money as necessary to pay expenses, liabilities and obligations of the Trust that cannot be paid out of cash held by the Trust, the Trust is prohibited from engaging in borrowing transactions. As a result, other than such borrowings, if any, the Trust has no source of liquidity or capital resources other than the Royalties.

Results of Operations

Royalty income received by the Trust for the three-year period ended December 31, 2018, is reported in the following table:

Royalties	Year Ended December 31,		
	2018	2017	2016
Total Revenue	\$ 32,088,282	\$ 30,559,527	\$ 21,087,908
	100%	100%	100%
Oil Revenue	25,349,742	23,225,240	16,870,326
	79%	76%	80%
Gas Revenue	6,738,540	7,334,287	4,217,582
	21%	24%	20%
Total Revenue/Unit	\$.688460	\$.655660	\$.452444

Royalty income of the Trust for the calendar year is associated with actual oil and gas production for the period November of the prior year through October of the current year. Oil and gas sales for 2018, 2017 and 2016 for the Royalties and the Underlying Properties, excluding portions attributable to the adjustments discussed hereafter, are presented in the following table:

Royalties	Year Ended December 31,		
	2018	2017	2016
Oil Sales (Bbls)	467,473	545,029	490,431
Gas Sales (Mcf)	1,595,999	1,984,978	1,590,681
Underlying Properties			
Oil			
Total Oil Sales (Bbls)	894,552	971,241	871,290
Average Per Day (Bbls)	2,451	2,661	2,381
Average Price/Bbl	\$ 58.11	\$ 45.88	\$ 39.73
Gas			
Total Gas Sales (Mcf)	3,960,107	4,293,545	3,764,922
Average Per Day (Mcf)	10,850	11,763	10,287

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Average Price/Mcf	\$	3.55	\$	3.28	\$	2.29
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The average price of oil increased to \$58.11 per barrel in 2018, up from \$45.88 per barrel in 2017. The average price of oil in 2016 was \$39.73 per barrel. In addition, the average price of gas increased from \$3.28 per Mcf in 2017 to \$3.55 per Mcf in 2018. The average price of gas in 2016 was \$2.29 per Mcf. Oil prices have increased primarily because of world market conditions. Oil prices are expected to remain volatile. Gas liquids values remain stronger and keep the prices of gas stronger.

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Subsequent to December 31, 2018, the price of both oil and gas continued to fluctuate, giving rise to a correlating adjustment of the respective standardized measure of discounted future net cash flows. As of February 28, 2019, NYMEX posted oil prices were approximately \$57.21 per barrel, which compared to the posted price of \$65.56 per barrel, used to calculate the worth of future net revenue of the Trust's proved developed reserves, would result in a smaller standardized measure of discounted future net cash flows for oil. As of February 28, 2019, NYMEX posted gas prices were \$2.89 per million British thermal units. The use of such price, as compared to the posted price of \$3.11 per million British thermal units, used to calculate the future net revenue of the Trust's proved developed reserves would result in a smaller standardized measure of discounted future net cash flows for gas.

Since the oil and gas sales attributable to the Royalties are based on an allocation formula that is dependent on such factors as price and cost (including capital expenditures), production amounts do not necessarily provide a meaningful comparison. For the underlying properties total oil production decreased by approximately .8% from 2017 to 2018 primarily due to the previous year's allocation of reduced expenses resulting in an increase of production. For the underlying properties total gas production decreased approximately .8% from 2017 to 2018 primarily due to the allocation of reduced expenses resulting in an increase of production.

On May 2, 2011, ConocoPhillips, as the parent company of BROG, the operator of the Waddell Ranch properties, notified the Trustee that as a result of inaccuracies in ConocoPhillips' accounting and record keeping relating to the Trust's interest in proceeds from the gas plant production since January 2007, ConocoPhillips overpaid the Trust approximately \$5.9 million initially. ConocoPhillips withheld \$4.5 million from the proceeds for 2011 pending completions to the corrections of the accounting procedures. Beginning with the October 2012 distribution, previously withheld proceeds of \$4.5 million were reimbursed by ConocoPhillips to the Trust (\$4.0 million and \$0.5 million in 2013 and 2012, respectively). ConocoPhillips has adjusted the monthly royalty payments to the Trust since October 2012 by the related reimbursed amounts to reflect ConocoPhillips' ongoing correction of past and current production and royalty allocations and the payment of the previously withheld proceeds. These adjustments were completed in the first quarter of 2015. The Trust's reported royalty income for the years ended December 31, 2018, 2017 and 2016 was not significantly impacted by these offsetting amounts. At this time, the Trustee considers all such corrections and adjustment to be accurate and fairly performed.

Total capital expenditures in 2018 used in the net overriding royalty calculation were approximately \$730,000 (gross) compared to \$1.9 million (gross) in 2017 and \$2.2 million (gross) in 2016. The operator of the Waddell Ranch properties has informed the Trustee that, in order to halt the production decline curve and to exploit the remaining potential of the Trust's assets more fully, a more aggressive, robust capital expenditure budget will be necessary in the future and is being pursued.

In 2017, there were 1 recompletion wells completed and 26 wells permanently plugged on the Waddell Ranch properties. Actual costs for this program in 2017 approximated \$1.4 million (gross). This cost is for the development program and base facilities. The new drills and recompletions, on average, provided a total of an additional 8 BOEPD to the exit rate annualized average. In 2018, there were 0 new drill wells and 0 recompletion.

Texas law requires all temporarily abandoned wells to be either worked over and recompleted to functional status or permanently plugged and abandoned within a five year time frame. The Waddell Ranch properties contain over 700 such temporarily abandoned wells. In 2018, there was 0 recompletion wells completed and 19 wells permanently plugged on the Waddell Ranch properties. Actual costs for this program in 2018 approximated \$1.01 million (gross). This cost is for the development program and base facilities. The recompletions, on average, provided a total of an additional 0 BOEPD to the exit rate annualized average as of December 2018. Production reported is gross.

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There were 0 gross (0 net) drill wells completed on the Waddell Ranch properties during 2018. At December 31, 2018, there was 1 drill well and 1 workover in progress on the Waddell Ranch properties.

The operator has advised the Trustee that the proposed budget for 2019 will be \$6.6 million (gross) and \$2.9 million (net). The 2019 budget will include amounts to be spent on no vertical wells, 2 wells to be worked over and completed,

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additional facilities and infrastructure improvements and the completion of projects begun in 2018, spending about \$2.4 million on this.

In 2018, lease operating expense and property taxes on the Waddell Ranch properties amounted to approximately \$23.1 million. In 2017, lease operating expense and property taxes on the Waddell Ranch properties amounted to approximately \$16.4 million. In 2016, lease operating expense and property taxes on the Waddell Ranch properties amounted to approximately \$12.9 million.

The Trustee has been advised by BROG that since June 2006, the oil from the Waddell Ranch has been marketed by ConocoPhillips by soliciting bids from third parties on an outright sale basis of production listed in bid packages.

During 2018, the monthly royalty receipts were invested by the Trustee until the monthly distribution date, and earned interest totaled \$26,006. Interest income for 2017 and 2016 was \$12,675 and \$2,643, respectively.

General and administrative expenses in 2018 were \$1,324,828 compared to \$1,246,786 in 2017 and \$1,191,716 in 2016, primarily due to audit of properties and other professional services. The reserve for administrative expenses for any potentially extraordinary events and/or expenses was \$1,050,000 as of December 31, 2018. Total reserves for expenses for the years ended December 31, 2018, 2017 and 2016 was \$0, \$0 and \$550,000, respectively.

Distributable income for 2018 was \$30,789,460 or \$.66 per Unit.

Distributable income for 2017 was \$29,325,416 or \$.63 per Unit.

Distributable income for 2016 was \$19,348,835 or \$0.42 per Unit.

Results of the Fourth Quarters of 2018 and 2017

Royalty income received by the Trust for the fourth quarter of 2018 amounted to \$7,509,505 or \$0.16 per Unit. For the fourth quarter of 2017, the Trust received royalty income of \$7,438,049 or \$0.155855 per Unit. Interest income for the fourth quarter of 2018 amounted to \$6,782 compared to \$4,067 for the fourth quarter of 2017. The increase in interest income can be attributed primarily to an increase of funds available. Total general and administrative expenses was \$143,389 for the fourth quarter of 2018 compared to \$177,860 for the fourth quarter of 2017. The decrease in expenses primarily related to a decrease in legal and auditor expenses.

Royalty income for the Trust for the fourth quarter is associated with actual oil and gas production during August through October from the Underlying Properties. Oil and gas sales attributable to the Royalties and the Underlying Properties for the quarter and the comparable period for 2017 are as follows:

	Fourth Quarter	
	2018	2017
Royalties		
Oil Sales (Bbls)	112,630	132,272
Gas Sales (Mcf)	391,770	478,585
Underlying Properties		
Total Oil Sales (Bbls)	220,842	250,512
Average Per Day (Bbls)	2,400	2,723

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Average Price/Bbls	\$ 55.09	\$ 46.36
Total Gas Sales (Mcf)	983,360	1,064,951
Average Per Day (Mcf)	10,689	11,576
Average Price/Mcf	\$ 3.68	\$ 3.53

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The posted price of oil increased for the fourth quarter of 2018 compared to the fourth quarter of 2017, resulting in an average price per barrel of \$55.09 compared to \$46.36 in the same period of 2017. The average price of gas increased for the fourth quarter of 2018 compared to the same period in 2017, resulting in an average price per Mcf of \$3.68 compared to \$3.53 in the fourth quarter of 2017.

The Trustee has been advised that oil production decreased in the fourth quarter of 2018 compared to the same period in 2017 primarily due to market pricing. Gas production decreased in the fourth quarter of 2018 compared to the same period in 2017 due to pricing pressure from market supply.

The Trust has been advised that 0 wells were drilled and completed during the three months ended December 31, 2018, and there were 2 wells in progress.

Use of Estimates

The preparation of financial statements in conformity with the basis of accounting described above requires management to make estimates and assumptions that affect reported amounts of certain assets, liabilities, revenues and expenses as of and for the reporting periods. Actual results may differ from such estimates.

Impairment

The Trustee routinely reviews its royalty interests in oil and gas properties for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If an impairment event occurs and it is determined that the carrying value of the Trust's royalty interests may not be recoverable, an impairment will be recognized as measured by the amount by which the carrying amount of the royalty interests exceeds the fair value of these assets, which would likely be measured by discounting projected cash flows. There was no impairment of the assets as of December 31, 2018.

Critical Accounting Policies and Estimates

The Trust's financial statements reflect the selection and application of accounting policies that require the Trust to make significant estimates and assumptions. The following are some of the more critical judgment areas in the application of accounting policies that currently affect the Trust's financial condition and results of operations.

1. Basis of Accounting

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

Royalty income recorded for a month is the amount computed and paid to the Trustee on behalf of the Trust by the interest owners. Royalty income consists of the amounts received by the owners of the interest burdened by the Royalties from the sale of production less accrued production costs, development and drilling costs, applicable taxes, operating charges and other costs and deductions multiplied by 75% in the case of the Waddell Ranch properties and 95% in the case of the Texas Royalty properties.

Trust expenses, consisting principally of routine general and administrative costs, recorded are based on liabilities paid and cash reserves established out of cash received or borrowed funds for liabilities and

contingencies.

Distributions to Unit holders are recorded when declared by the Trustee.

Royalty income is computed separately for each of the conveyances under which the Royalties were conveyed to the Trust. If monthly costs exceed revenues for any conveyance (excess costs), such excess costs cannot reduce royalty income from other conveyances, but is carried forward with accrued interest to be recovered from future net proceeds of that conveyance.

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The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) because revenues are not accrued in the month of production and certain cash reserves may be established for contingencies which would not be accrued in financial statements prepared in accordance with GAAP. Amortization of the Royalties calculated on a unit-of-production basis is charged directly to trust corpus. 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.

2. Revenue Recognition

Revenues from Royalty Interests are recognized in the period in which amounts are received by the Trust. Royalty income received by the Trust in a given calendar year will generally reflect the proceeds from crude oil and natural gas produced for the twelve-month period ended October 31st in that calendar year.

3. Reserve Disclosure

Independent petroleum engineers estimate the net proved reserves attributable to the Royalty Interests. Estimates of future net revenues from proved reserves have been prepared using average 12-month oil and gas prices, determined as an unweighted arithmetic average of the first-day-of-the-month benchmark price for each month within the 12-month period preceding the end of the most recent fiscal year, unless prices are defined by contractual arrangements. 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 gas reserves. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates and related costs. Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and the timing of development of non-producing reserves. Such reserve estimates are subject to change as market conditions change.

Detailed information concerning the number of wells on royalty properties is not generally available to the owner of royalty interests. Consequently, the Registrant does not have information that would be disclosed by a company with oil and gas operations, such as an accurate account of the number of wells located on its royalty properties, the number of exploratory or development wells drilled on its royalty properties during the periods presented by this report, or the number of wells in process or other present activities on its royalty properties, and the Registrant cannot readily obtain such information.

4. Contingencies

Contingencies related to the Underlying Properties that are unfavorably resolved would generally be reflected by the Trust as reductions to future royalty income payments to the Trust with corresponding reductions to cash distributions to Unit holders.

New Accounting Pronouncements

Revenue Recognition In May 2014, the FASB issued updated guidance for recognizing revenue from contracts with customers. This update amends the existing accounting standards for revenue recognition and is based on the principle that revenue should be recognized to depict the transfer of goods and services to a customer at an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The Trust adopted this standards update, as required, beginning with the first quarter of 2018, but does not believe the adoption of this standard will have a significant impact on its financial statements due to the modified cash basis of reporting used by

the Trust.

Off-Balance Sheet Arrangements.

As stipulated in the Trust Agreement, the Trust is intended to be passive in nature and the Trustee does not have any control over or any responsibility relating to the operation of the Underlying Properties. The Trustee has powers to collect and distribute proceeds received by the Trust and pay Trust liabilities and expenses and its actions have been limited to those activities. Therefore, the Trust has not engaged in any off-balance sheet arrangements.

Table of Contents**Tabular Disclosure of Contractual Obligations.**

Contractual Obligations	Total	Less than 1 Year	Payments Due by Period More than		
			1 - 3 Years	3 - 5 Years	5 Years
Distribution payable to Unit holders	\$ 2,476,613	\$ 2,476,613	\$ 0	\$ 0	\$ 0
Total	\$ 2,476,613	\$ 2,476,613	\$ 0	\$ 0	\$ 0

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

The Trust is a passive entity and other than the Trust's ability to periodically borrow money as necessary to pay expenses, liabilities and obligations of the Trust that cannot be paid out of cash held by the Trust, the Trust is prohibited from engaging in borrowing transactions. The amount of any such borrowings is unlikely to be material to the Trust. The Trust periodically holds short-term investments acquired with funds held by the Trust pending distribution to Unit holders and funds held in reserve for the payment of Trust expenses and liabilities. Because of the short-term nature of these borrowings and investments and certain limitations upon the types of such investments which may be held by the Trust, the Trustee believes that the Trust is not subject to any material interest rate risk. The Trust does not engage in transactions in foreign currencies which could expose the Trust or Unit holders to any foreign currency related market risk. The Trust invests in no derivative financial instruments and has no foreign operations or long-term debt instruments.

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Item 8. *Financial Statements and Supplementary Data*
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Unit Holders of Permian Basin Royalty Trust and

Simmons Bank, Trustee

Opinion on the Financial Statements

We have audited the accompanying statements of assets, liabilities and trust corpus of the Permian Basin Royalty Trust (the 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 (collectively referred to as the financial statements). In our opinion, the financial statements present fairly, in all material respects, the assets, liabilities, and trust corpus of the Trust as of December 31, 2018 and 2017, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2018, in conformity with the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

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

As described in Note 2 to the financial statements, these financial statements were prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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/ WEAVER AND TIDWELL, L.L.P.

We have served as the Trust's auditor since 2016.

Dallas, Texas

March 18, 2019

Table of Contents**PERMIAN BASIN ROYALTY TRUST****FINANCIAL STATEMENTS****STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS**

	December 31,	
	2018	2017
ASSETS		
Cash and Short-term Investments	\$ 3,526,613	\$ 3,421,419
Net Overriding Royalty Interests in Producing Oil and Gas Properties Net (Notes 2 and 3)	467,580	529,043
Total	\$ 3,994,193	\$ 3,950,462
LIABILITIES AND TRUST CORPUS		
Distribution Payable to Unit Holders	\$ 2,476,613	\$ 2,371,419
Commitments and Reserve for Contingencies (Note 8)	1,050,000	1,050,000
Total Liabilities	\$ 3,526,613	\$ 3,421,419
Trust Corpus 46,608,796 Units of Beneficial Interest Authorized and Outstanding	467,580	529,043
Total	\$ 3,994,193	\$ 3,950,462

STATEMENTS OF DISTRIBUTABLE INCOME

	For the years ended December 31,		
	2018	2017	2016
Royalty Income (Notes 2 and 3)	\$ 32,088,282	\$ 30,559,527	\$ 21,087,908
Interest Income	26,006	12,675	2,643
	32,114,288	30,572,202	21,090,551
General and Administrative Expenditures	1,324,828	1,246,786	1,191,716
Reserve for Expenses			550,000
Total Expenditures	1,324,828	1,246,786	1,741,716
Distributable Income	\$ 30,789,460	\$ 29,325,416	\$ 19,348,835
Distributable Income per Unit (46,608,796 Units)	\$.66	\$.63	\$.42
Distributions per Unit	\$.66	\$.63	\$.42

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

Table of Contents**STATEMENTS OF CHANGES IN TRUST CORPUS**

	For the years ended December 31,		
	2018	2017	2016
Trust Corpus, Beginning of Year	\$ 529,043	\$ 603,119	\$ 680,686
Amortization of Net Overriding Royalty Interests (Notes 2 and 3)	(61,463)	(74,076)	(77,567)
Distributable Income	30,789,460	29,325,416	19,348,835
Distributions Declared	(30,789,460)	(29,325,416)	(19,348,835)
Trust Corpus, End of Year	\$ 467,580	\$ 529,043	\$ 603,119

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

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NOTES TO FINANCIAL STATEMENTS

1. Trust Organization and Provisions

The Permian Basin Royalty Trust (Trust) was established as of November 1, 1980. Simmons Bank (Trustee) is Trustee for the Trust. The net overriding royalties conveyed to the Trust include (1) a 75% net overriding royalty in Southland Royalty Company s fee mineral interest in the Waddell Ranch in Crane County, Texas (the Waddell Ranch properties) and (2) a 95% net overriding royalty carved out of Southland Royalty Company s major producing royalty properties in Texas (the Texas Royalty properties). The net overriding royalty for the Texas Royalty properties is subject to the provisions of the lease agreements under which such royalties were created. The net overriding royalties above are collectively referred to as the Royalties.

On November 3, 1980, Units of Beneficial Interest (Units) in the Trust were distributed to the Trustee for the benefit of Southland Royalty Company s shareholders of record as of November 3, 1980, who received one Unit in the Trust for each share of Southland Royalty Company common stock held. The Units are traded on the New York Stock Exchange.

Burlington Resources Oil & Gas Company LP (BROG), a subsidiary of ConocoPhillips, is the interest owner for the Waddell Ranch properties and Riverhill Energy Corporation (Riverhill Energy), formerly a wholly owned subsidiary of Riverhill Capital Corporation (Riverhill Capital) and formerly an affiliate of Coastal Management Corporation (CMC), is the interest owner for the Texas Royalty properties. BROG currently conducts all field, technical and accounting operations on behalf of BROG with regard to the Waddell Ranch properties. Riverhill Energy currently conducts the accounting operations for the Texas Royalty properties.

In February 1997, BROG sold its interest in the Texas Royalty properties to Riverhill Energy.

The Trustee was advised that in the first quarter of 1998, Schlumberger Technology Corporation (STC) acquired all of the shares of stock of Riverhill Capital. Prior to such acquisition by STC, CMC and Riverhill Energy were wholly owned subsidiaries of Riverhill Capital. The Trustee was further advised that in connection with STC s acquisition of Riverhill Capital, the shareholders of Riverhill Capital acquired ownership of all of the shares of stock of Riverhill Energy. Thus, the ownership in the Texas Royalty properties referenced above remained in Riverhill Energy, the stock ownership of which was acquired by the former shareholders of Riverhill Capital.

On January 9, 2014, Bank of America N.A. (as successor to The First National Bank of Fort Worth) gave notice to Unit holders that it would be resigning as trustee of the Trust subject to certain conditions that included the appointment of Southwest Bank as successor trustee. At a Special Meeting of Trust Unit holders, the Unit holders approved the appointment of Southwest Bank as successor trustee of the Trust once the resignation of Bank of America N.A. took effect and also approved certain amendments to the Trust Indenture. The effective date of Bank of America N.A. s resignation and the effective date of Southwest Bank s appointment as successor trustee was August 29, 2014. Effective October 19, 2017, Simmons First National Corporation (SFNC) completed its acquisition of First Texas BHC, Inc., the parent company of Southwest Bank. SFNC is the parent company of Simmons Bank. SFNC merged Southwest Bank with Simmons Bank effective February 20, 2018. The defined term Trustee as used herein shall refer to Bank of America N.A. for periods prior to August 29, 2014, and shall refer to Southwest Bank for periods from August 29, 2014 through February 19, 2018 and shall refer to Simmons Bank for periods on and after February 20, 2018.

The terms of the Trust Indenture provide, among other things, that:

the Trust shall not engage in any business or commercial activity of any kind or acquire any assets other than those initially conveyed to the Trust;

the Trustee may not sell all or any part of the Royalties unless approved by holders of 75% of all Units outstanding in which case the sale must be for cash and the proceeds promptly distributed;

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the Trustee may establish a cash reserve for the payment of any liability which is contingent or uncertain in amount;

the Trustee is authorized to borrow funds to pay liabilities of the Trust; and

the Trustee will make monthly cash distributions to Unit holders (see Note 3).

2. Accounting Policies

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

Royalty income recorded for a month is the amount computed and paid to the Trustee on behalf of the Trust by the interest owners. Royalty income consists of the amounts received by the owners of the interest burdened by the Royalties from the sale of production less accrued production costs, development and drilling costs, applicable taxes, operating charges and other costs and deductions multiplied by 75% in the case of the Waddell Ranch properties and 95% in the case of the Texas Royalty properties.

Trust expenses, consisting principally of routine general and administrative costs, recorded are based on liabilities paid and cash reserves established out of cash received or borrowed funds for liabilities and contingencies.

Distributions to Unit holders are recorded when declared by the Trustee.

Royalty income is computed separately for each of the conveyances under which the Royalties were conveyed to the Trust. If monthly costs exceed revenues for any conveyance (excess costs), such excess costs cannot reduce royalty income from other conveyances, but is carried forward with accrued interest to be recovered from future net proceeds of that conveyance.

The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) because revenues are not accrued in the month of production expenses are recorded when paid and certain cash reserves may be established for contingencies which would not be accrued in financial statements prepared in accordance with GAAP. Amortization of the Royalties calculated on a unit-of-production basis is charged directly to trust corpus. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission 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 management to make estimates and assumptions that affect reported amounts of certain assets, liabilities, revenues and expenses as of and for the reporting periods. Actual results may differ from such estimates.

Impairment

The Trustee routinely reviews its royalty interests in oil and gas properties for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If an impairment event occurs and it is determined that the carrying value of the Trust's royalty interests may not be recoverable, an impairment will be recognized as measured by the amount by which the carrying amount of the royalty interests exceeds the fair value of these assets, which would likely be measured by discounting projected cash flows. There was no impairment of the assets as of December 31, 2018.

Contingencies

Contingencies related to the Underlying Properties that are unfavorably resolved would generally be reflected by the Trust as reductions to future royalty income payments to the Trust with corresponding reductions to cash distributions to Unit holders.

Table of Contents***Distributable Income Per Unit***

Basic distributable income per Unit is computed by dividing distributable income by the weighted average of Units outstanding. Distributable income per Unit assuming dilution is computed by dividing distributable income by the weighted average number of Units and equivalent Units outstanding. The Trust had no equivalent Units outstanding for any period presented. Therefore, basic distributable income per Unit and distributable income per Unit assuming dilution are the same.

New Accounting Pronouncements

Revenue Recognition In May 2014, the FASB issued updated guidance for recognizing revenue from contracts with customers. This update amends the existing accounting standards for revenue recognition and is based on the principle that revenue should be recognized to depict the transfer of goods and services to a customer at an amount that reflects the consideration a company expects to receive in exchange for those goods or services. The Trust adopted this standards update, as required, beginning with the first quarter of 2018, but does not believe the adoption of this standard will have a significant impact on its financial statements due to the modified cash basis of reporting used by the Trust.

3. Net Overriding Royalty Interests and Distribution to Unit Holders

The amounts to be distributed to Unit holders (Monthly Distribution Amounts) are determined on a monthly basis. The Monthly Distribution Amount is an amount equal to the sum of cash received by the Trustee during a calendar month attributable to the Royalties, any reduction in cash reserves and any other cash receipts of the Trust, including interest, reduced by the sum of liabilities paid and any increase in cash reserves. If the Monthly Distribution Amount for any monthly period is a negative number, then the distribution will be zero for such month. To the extent the distribution amount is a negative number, that amount will be carried forward and deducted from future monthly distributions until the cumulative distribution calculation becomes a positive number, at which time a distribution will be made. Unit holders of record will be entitled to receive the calculated Monthly Distribution Amount for each month on or before 10 business days after the monthly record date, which is generally the last business day of each calendar month.

The cash received by the Trustee consists of the amounts received by owners of the interest burdened by the Royalties from the sale of production less the sum of applicable taxes, accrued production costs, development and drilling costs, operating charges and other costs and deductions, multiplied by 75% in the case of the Waddell Ranch properties and 95% in the case of the Texas Royalty properties.

The initial carrying value of the Royalties (\$10,975,216) represented Southland Royalty Company's historical net book value at the date of the transfer to the Trust. Accumulated amortization as of December 31, 2018 and 2017 was \$10,507,636 and \$10,446,173, respectively.

4. Federal Income Taxes

For federal income tax purposes, the Trust constitutes a fixed investment trust that is taxed as a grantor trust. A grantor trust is not subject to tax at the trust level. The Unit holders are considered to own the Trust's income and principal as though no trust were in existence. The income of the Trust is deemed to have been received or accrued by each Unit holder at the time such income is received or accrued by the Trust and not when distributed by the Trust.

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The Trust has on file technical advice memoranda confirming the tax treatment described above.

Some Trust Units are held by middlemen, 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 customer in 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. Simmons Bank, EIN: 71-0162300, 2911 Turtle Creek Boulevard, Suite 850, Dallas, Texas 75219, telephone number (855) 588-7839, email address

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trustee@pbt-permian.com, 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.pbt-permian.com. Notwithstanding the foregoing, the middlemen holding Trust Units on behalf of Unit holders, 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 Trust Units, including the issuance of IRS Forms 1099 and certain written tax statements. Unit holders 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.

Because the Trust is a grantor trust for federal tax purposes, each Unit holder is taxed directly on his proportionate share of income, deductions and credits of the Trust consistent with each such Unit holder's taxable year and method of accounting and without regard to the taxable year or method of accounting employed by the Trust. The income of the Trust consists primarily of a specified share of the proceeds from the sale of oil and gas produced from the Underlying Properties. During 2018, the Trust also earned interest income on funds held for distribution and the cash reserve maintained for the payment of contingent and future obligations of the Trust.

The Trust generally allocates its items of income, gain, loss and deduction between transferors and transferees of the Units each month based upon the ownership of the Units on the monthly record date, instead of on the basis of the date a particular 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 Unit holders affected by the issue and result in an increase in the administrative expense of the Trust in subsequent periods.

The deductions of the Trust consist of severance taxes and administrative expenses. In addition, each Unit holder is entitled to depletion deductions because the Royalties constitute economic interests in oil and gas properties for federal income tax purposes. Each Unit holder is entitled to amortize the cost of the Units through cost depletion over the life of the Royalties or, if greater, through percentage depletion equal to 15 percent of gross income, limited to 100% of the net income from such royalty. Unlike cost depletion, percentage depletion is not limited to a Unit holder's depletable tax basis in the Units. Rather, a Unit holder is entitled to a percentage depletion deduction as long as the applicable Underlying Properties generate gross income. Percentage depletion is allowed on proven properties acquired after October 11, 1990. For Units acquired after such date, Unit holders should compute both percentage depletion and cost depletion from each property and claim the larger amount as a deduction on their income tax returns. The Trustee has estimated the cost depletion for January through December 2018, and it appears that percentage depletion will exceed cost depletion for some of the Unit holders.

Unit holders must maintain records of their adjusted basis in their Trust Units (generally his cost less prior depletion deductions), make adjustments for depletion deductions to such basis, and use the adjusted basis for the computation of gain or loss on the disposition of the Trust Units.

If a taxpayer disposes of any Section 1254 property (certain oil, gas, geothermal or other mineral property), and if the adjusted basis of such property includes adjustments for deductions for depletion under Section 611 of the Internal Revenue Code (the Code), the taxpayer generally must recapture the amount deducted for depletion as ordinary income (to the extent of gain realized on such disposition). 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 Internal Revenue Service likely will take the position that a Unit holder who purchases a Unit subsequent to December 31, 1986 must recapture depletion upon the disposition of that Unit.

Individuals may incur expenses in connection with the acquisition or ownership of Trust Units. For tax years beginning before January 1, 2018, these expenses may be deductible as miscellaneous itemized deductions only to the extent that such expenses exceed 2 percent of the individual's adjusted gross income. As a result of recently-enacted tax legislation under the TCJA, for tax years beginning after December 31, 2018 and before January 1, 2026, miscellaneous itemized deductions are not allowed.

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The classification of the Trust's income for purposes of the passive loss rules may be important to a Unit holder. Royalty income generally is treated as portfolio income and does not offset passive losses. Therefore, in general, Unit holders should not consider the taxable income from the Trust to be passive income in determining net passive income or loss. Unit holders should consult their tax advisors for further information.

Unit holders of record will continue to receive an individualized tax information letter for each of the quarters ending March 31, June 30 and September 30, 2018, and for the year ending December 31, 2018. Unit holders owning Units in the name of a nominee may obtain monthly tax information from the Trustee upon request. See discussion above regarding certain reporting requirements imposed upon middlemen under U.S. Treasury Regulations because the Trust is considered a WHIFT for federal income tax purposes.

Under the TCJA, for tax years beginning after December 31, 2018 and before January 1, 2026, 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 20%. Under the TCJA, for such tax years, personal exemptions and miscellaneous itemized deductions are not allowed. For such tax years, the U.S. federal income tax rate applicable to corporations is 21%, and such rate applies to both ordinary income and capital gains.

For tax years beginning before January 1, 2018, the highest marginal U.S. federal income tax rate applicable to ordinary income of individuals is 39.6%, and the highest marginal U.S. federal income tax rate applicable to long-term capital gains and qualified dividends of individuals is 20%. For such pre-2018 tax years, such marginal tax rates may be effectively increased by up to 1.2% due to the phaseout of personal exemptions and the limitations on itemized deductions. For such pre-2018 tax years, the highest marginal U.S. federal income tax rate applicable to corporations is 35%, 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. For these purposes, investment income generally will include a Unit holder'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 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.

The Tax consequences to a Unit holder of the acquisition, ownership or disposition of Units will depend in part on the Unit holder's tax circumstances. Unit holders should consult their tax advisors regarding the federal tax consequences relating to acquiring, owning or disposing the Units in the Trust.

Pursuant to the Foreign Account Tax Compliance Act (commonly referred to as FATCA), distributions from the Trust to foreign financial institutions and certain other non-financial foreign entities may be subject to U.S. withholding taxes. Specifically, certain withholdable payments (including certain royalties, interest and other gains or income from U.S. sources) made to a foreign financial institution or non-financial foreign entity will generally be subject to the withholding tax unless the foreign financial institution or non-financial foreign entity complies with certain information reporting, withholding, identification, certification and related requirements imposed by FATCA. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing FATCA may be subject to different rules.

The Treasury Department issued guidance providing that the FATCA withholding rules described above generally apply to qualifying payments made after June 30, 2014. Foreign Unit holders are encouraged to consult their own tax advisors regarding the possible implications of these withholding provisions on their investment in Trust Units.

Table of Contents**5. Proved Oil and Gas Reserves (Unaudited)****Reserve Quantities**

Information regarding estimates of the proved oil and gas reserves attributable to the Trust are based on reports prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineering consultants. Estimates were prepared in accordance with the guidelines established by the FASB and the Securities and Exchange Commission. Certain information required by this guidance is not presented because that information is not applicable to the Trust due to its passive nature.

Oil and gas reserve quantities (all located in the United States) are estimates based on information available at the time of their preparation. Such estimates are subject to change as additional information becomes available. Reserves actually recovered, and the timing of the production of those reserves, may differ substantially from original estimates. The following schedule presents changes in the Trust's total proved reserves (in thousands):

	Total	
	Oil (Bbls)	Gas (Mcf)
January 1, 2016	4,610	9,046
Extensions, discoveries, and other additions	85	152
Revisions of previous estimates	164	518
Production	(404)	(1,198)
December 31, 2016	4,455	8,518
Extensions, discoveries, and other additions	31	649
Revisions of previous estimates	665	3,320
Production	(545)	(1,985)
December 31, 2017	4,606	10,502
Extensions, discoveries, and other additions	46	109
Revisions of previous estimates	78	(1098)
Production	(469)	(1609)
December 31, 2018	4,261	7,904

Estimated quantities of proved developed reserves of oil and gas as of the dates indicated were as follows (in thousands):

	Oil (Barrels)	Gas (Mcf)
Proved Developed Reserves:		
January 1, 2016	4,610	9,046
December 31, 2016	4,455	8,518
December 31, 2017	4,606	10,502
December 31, 2018	4,261	7,904

Disclosure of a Standardized Measure of Discounted Future Net Cash Flows

The following is a summary of a standardized measure (in thousands) of discounted future net cash flows related to the Trust's total proved oil and gas reserve quantities. Information presented is based upon valuation of proved reserves by using discounted cash flows based upon average oil and gas prices (\$65.56 per bbl and \$3.11 per Mcf, respectively) during the 12-month period prior to the fiscal year-end, 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 and severance and ad valorem taxes, if any, and economic conditions, discounted at the required rate of 10 percent. As the Trust is not subject to taxation at the trust level, no provision for income taxes has been made in the following disclosure. Trust prices may differ from posted

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NYMEX prices due to differences in product quality and property location. The impact of changes in current prices on reserves could vary significantly from year to year. Accordingly, the information presented below should not be viewed as an estimate of the fair market value of the Trust's oil and gas properties nor should it be viewed as indicative of any trends.

December 31,	2018	2017	2016
Future net cash inflows	\$ 270,462	\$ 245,571	\$ 188,269
Discount of future net cash flows @ 10%	(131,044)	(115,661)	(90,192)
Standardized measure of discounted future net cash inflows	\$ 139,418	\$ 129,910	\$ 98,077

The change in the standardized measure of discounted future net cash flows for the years ended December 31, 2018, 2017 and 2016 is as follows (in thousands):

	2018	Total 2017	2016
January 1	\$ 129,910	\$ 98,077	\$ 126,105
Extensions, discoveries, and other additions	994	2,093	1,347
Accretion of discount	12,991	9,808	12,610
Revisions of previous estimates and other	27,561	50,491	(20,898)
Royalty income	(32,038)	(30,559)	(21,087)
December 31	\$ 139,418	\$ 129,910	\$ 98,077

Subsequent to December 31, 2018, the price of both oil and gas continued to fluctuate, giving rise to a correlating adjustment of the respective standardized measure of discounted future net cash flows. As of February 28, 2019, NYMEX posted oil prices were approximately \$57.21 per barrel, which compared to the posted price of \$65.56 per barrel, used to calculate the worth of future net revenue of the Trust's proved developed reserves, would result in a larger standardized measure of discounted future net cash flows for oil. As of February 28, 2019, NYMEX posted gas prices were \$2.89 per million British thermal units. The use of such price, as compared to the posted price of \$3.112 per million British thermal units, used to calculate the future net revenue of the Trust's proved developed reserves would result in a smaller standardized measure of discounted future net cash flows for gas.

Table of Contents**6. Quarterly Schedule of Distributable Income (Unaudited)**

The following is a summary of the unaudited quarterly schedule of distributable income for the two years ended December 31, 2018 (in thousands, except per Unit amounts):

	Royalty Income	Distributable Income	Distributable Income and Distribution Per Unit
2018			
First Quarter	\$ 9,719,305	\$ 9,310,931	\$.199767
Second Quarter	7,623,122	7,048,414	.151225
Third Quarter	7,236,350	7,056,843	.151405
Fourth Quarter	7,509,505	7,373,272	.158195
Total	\$ 32,088,282	\$ 30,789,460	\$ 0.660592

	Royalty Income	Distributable Income	Distributable Income and Distribution Per Unit
2017			
First Quarter	\$ 9,552,223	\$ 9,189,048	\$.197153
Second Quarter	7,473,738	6,971,797	.149581
Third Quarter	6,095,517	5,900,315	.126592
Fourth Quarter	7,438,049	7,264,256	.155855
Total	\$ 30,559,527	\$ 29,325,416	\$.629181

7. State Tax Considerations

All revenues from the Trust are from sources within Texas, which does not impose an individual income tax. Texas imposes a franchise tax at a rate of 0.75% on gross revenues less certain deductions, as specifically set forth in the Texas franchise tax statutes. Entities subject to tax generally include trusts and most other types of entities that provide limited liability protection, unless otherwise exempt. Trusts that receive at least 90% of their federal gross income from certain passive sources, including royalties from mineral properties and other non-operated mineral interest income, 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. The Trust has been and expects to continue to be exempt from Texas franchise tax as a passive entity. Because the Trust should be exempt from Texas franchise tax at the Trust level as a passive entity, each Unit holder that is a taxable entity under the Texas franchise tax generally will be required to include its portion of Trust revenues in its own Texas franchise tax computation. This revenue is sourced to Texas under provisions of the Texas Administrative Code providing that such income is sourced according to the principal place of business of the Trust, which is Texas.

Unit holders should consult their tax advisors regarding the possible state tax implications of owning Trust Units.

8. Commitments and Contingencies

Contingencies related to the Underlying Properties that are unfavorably resolved would generally be reflected by the Trust as reductions to future royalty income payments to the Trust with corresponding reductions to cash distributions to Unit holders.

On May 2, 2011, ConocoPhillips, as the parent company of BROG, the operator of the Waddell Ranch properties, notified the Trustee that as a result of inaccuracies in ConocoPhillips' accounting and record keeping relating to the Trust's interest in proceeds from the gas plant production since January 2007, ConocoPhillips overpaid the Trust approximately \$5.9 million initially. ConocoPhillips withheld \$4.5 million from the proceeds for 2011 pending completions to the corrections of the accounting procedures. Beginning with the October 2012 distribution, previously

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withheld proceeds of \$4.5 million were reimbursed by ConocoPhillips to the Trust (\$4.0 million and \$0.5 million in 2013 and 2012, respectively). ConocoPhillips has adjusted the monthly royalty payments to the Trust since October 2012 by the related reimbursed amounts to reflect ConocoPhillips' ongoing correction of past and current production and royalty allocations and the payment of the previously withheld proceeds. These adjustments were completed in the first quarter of 2015. The Trust's reported royalty income for the years ended December 31, 2018, 2017 and 2016 was not significantly impacted by these offsetting amounts. The Trustee is continuing to evaluate the matter. In conclusion, the Trustee found such calculations and subsequent adjustments to be as accurate as can be determined.

9. Subsequent Events

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

Monthly Record Date	Payment Date	Distribution per Unit
January 31, 2019	February 14, 2019	\$.033628
February 28, 2019	March 14, 2019	\$.031624

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

None.

Item 9A. *Controls and Procedures.*

Disclosure Controls and Procedures

As of the end of the period covered by this report, the Trustee carried out an evaluation of the effectiveness of the design and operation of the Trust's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 promulgated under the Securities Exchange Act of 1934, as amended. Based on such evaluation, the Trustee concluded that the Trust's disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to the Trustee to allow timely decisions regarding required disclosure.

In its evaluation of disclosure controls and procedures, the Trustee has relied, to the extent considered reasonable, on information provided by Burlington Resources Oil & Gas Company, LP, the owner of the Waddell Ranch properties, and Riverhill Energy Corporation, the owner of the Texas Royalty properties.

Changes in Internal Control over Financial Reporting

There has not been any change in the Trust's internal control over financial reporting during the nine months ended December 31, 2018 that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting.

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 Securities and Exchange Act of 1934, as amended. 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 are effective as of December 31, 2018.

The independent registered public accounting firm of Weaver and Tidwell, L.L.P., as auditors of the statements of assets, liabilities, and trust corpus, and the related statements of distributable income and changes in trust corpus for the year ended December 31, 2018, has issued an attestation report on the Trust's internal control over financial reporting as of December 31, 2018, which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Unit Holders of Permian Basin Royalty Trust and

Simmons Bank, Trustee

Opinion on Internal Control Over Financial Reporting

We have audited Permian Basin Royalty Trust (the Trust) s internal control over financial reporting as of December 31, 2018 based on criteria established in *Internal Control – Integrated Framework* 2013 issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). In our opinion, 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 Permian Basin 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 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 Permian Basin Royalty 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 of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 the modified cash basis of accounting described in Note 2 to the financial statements. 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 the modified cash basis of accounting described in Note 2 to the financial statements, and that receipts and expenditures of the entity are being made only in accordance with authorizations of the Trustee 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/ WEAVER AND TIDWELL, L.L.P.

Dallas, Texas

March 18, 2019

Table of Contents**Item 9B. Other Information.**

None.

PART III**Item 10. Directors and Executive Officers of the Registrant****DIRECTORS AND OFFICERS**

The Trust has no directors or executive officers. The Trustee is a corporate trustee which may be removed, with or without cause, at a meeting of the Unit holders, by the affirmative vote of the holders of a majority of all the Units then outstanding.

AUDIT COMMITTEE AND NOMINATING COMMITTEE

Because the Trust has no directors, it does not have an audit committee, an audit committee financial expert or a nominating committee.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange Act of 1934, as amended, requires the Trust's directors, officers or beneficial owners of more than ten percent of a registered class of the Trust's equity securities to file reports of ownership and changes in ownership with the SEC and to furnish the Trust with copies of all such reports.

The Trust has no directors or officers and based solely on its review of the reports received by it, the Trust believes that during the fiscal year of 2018, no person who was a beneficial owner of more than ten percent the Trust's Units failed to file on a timely basis any report required by Section 16(a).

STANDARDS OF CONDUCT

Because the Trust has no employees, it does not have a code of ethics. Employees of the Trustee, Simmons Bank, must comply with the bank's code of ethics which may be found at ir.simmonsbank.com/govdocs.

Item 11. Executive Compensation

During the years ended December 31, 2018, 2017 and 2016, the Trustee received total remuneration as follows:

Name of Individual or Number of Persons in Group	Cash	
	Compensation	Year
Simmons Bank, Trustee	\$ 95,480(1)	2018
Southwest Bank, Trustee	\$ 15,190(1)	2018
	\$ 111,155(1)	2017
	\$ 93,244(1)	2016

- (1) Under the Trust Indenture, the Trustee is entitled to an administrative fee for its administrative services, preparation of quarterly and annual statements with attention to tax and legal matters of: (i) 1/20 of 1% of the first \$100 million and (ii) Trustee's standard hourly rate in excess of 300 hours annually. The administrative fee is subject to reduction by a credit for funds provision.

Table of Contents**COMPENSATION COMMITTEE**

Because the Trust has no directors, it does not have a compensation committee or maintain any equity compensation plans, and the Trust has not engaged any consultants to provide advice or recommendations on the amount or form of compensation. The Trust does not have a principal executive officer or employees and therefore, the pay ratio disclosure is not applicable.

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

(a) *Security Ownership of Certain Beneficial Owners.* Based solely on a review of statements filed with the SEC pursuant to Section 13(d) or 13(g) of the Securities Exchange Act of 1934, as amended, the following table sets forth all persons who are known to the Trustee to own beneficially more than 5% of the outstanding Units of the Trust as of December 31, 2018:

Name	Number of Units	
	Owned(1)	Percent(2)
Loyd Powell(3)	1,246,655	2.67%
Gideon Powell(3)	1,287,004	2.76%

(1) Unless otherwise indicated, all Units are held directly with sole voting and investment power.

(2) Based on 46,608,796 Units outstanding as of December 31, 2018.

(3) Based on Schedule 13G filed April 26, 2017, reporting ownership as of April 17, 2017, jointly and as a group by Loyd Powell and Gideon Powell. The address for each of Loyd Powell and Gideon Powell is 6688 North Central Expressway; Suite 1610, Dallas, Texas 75206.

(b) *Security Ownership of Management.* The Trustee does not beneficially own any securities of the Trust.

(c) *Change In Control.* The Trustee knows of no arrangements which may subsequently result in a change in control of the Trust.

(d) *Securities Authorized for Issuance under Equity Compensation Plans.* The Trust has no equity compensation plans.

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

The Trust has no directors or executive officers. See Item 11 for the remuneration received by the Trustee during the years ended December 31, 2018, 2017 and 2016.

Item 14. Principal Accounting Fees and Services

Fees for services performed by Weaver and Tidwell, L.L.P. for the years ended December 31, 2018 and 2017 are:

Weaver and Tidwell, L.L.P.	2018	2017
Audit fees	\$ 94,000	\$ 100,000
Audit-related fees		
Tax fees		
All other fees		
Total	\$ 94,000	\$ 100,000
Total	94,000	\$ 100,000

As referenced in Item 10 above, the Trust has no audit committee, and as a result, has no audit committee pre-approval policy with respect to fees paid to Weaver and Tidwell, L.L.P.

Table of Contents**PART IV****Item 15. Exhibits, Financial Statement Schedules**

The following documents are filed as a part of this Report:

1. *Financial Statements*

Included in Part II of this Report:

<u>Reports of Independent Registered Public Accounting Firm</u>	30
<u>Statements of Assets, Liabilities and Trust Corpus at December 31, 2018 and 2017</u>	31
<u>Statements of Distributable Income for Each of the Three Years in the Period Ended December 31, 2018</u>	31
<u>Statements of Changes in Trust Corpus for Each of the Three Years in the Period Ended December 31, 2018</u>	32
<u>Notes to Financial Statements</u>	33

2. *Financial Statement Schedules*

Financial statement schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. *Exhibits***Exhibit****Number****Exhibit**

- (4)(a) Permian Basin Amended and Restated Royalty Trust Indenture dated June 20, 2014, between Southland Royalty Company (now Burlington Resources Oil & Gas Company LP) and The First National Bank of Fort Worth (now Simmons Bank), as Trustee, heretofore filed as Exhibit 4.1 to the Trust's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarterly period ended June 30, 2014, is incorporated herein by reference.*
- (b) Net Overriding Royalty Conveyance (Permian Basin Royalty Trust) from Southland Royalty Company (now Burlington Resources Oil & Gas Company LP) to The First National Bank of Fort Worth (now Simmons Bank), as Trustee, dated November 3, 1980 (without Schedules), heretofore filed as Exhibit (4)(b) to the Trust's Annual Report on Form 10-K to the Securities and Exchange Commission for the fiscal year ended December 31, 1980, is incorporated herein by reference.* (P)
- (c) Net Overriding Royalty Conveyance (Permian Basin Royalty Trust - Waddell Ranch) from Southland Royalty Company (now Burlington Resources Oil & Gas Company LP) to The First National Bank of Fort Worth (now Simmons Bank), as Trustee, dated November 3, 1980 (without Schedules), heretofore filed as Exhibit (4)(c) to the Trust's Annual Report on Form 10-K to the Securities and Exchange Commission for the fiscal year ended December 31, 1980, is incorporated herein by reference.* (P)

- (10)(a) Underwriting Agreement dated December 15, 2005 among the Permian Basin Royalty Trust, Burlington Resources, Inc., Burlington Resources Oil & Gas L.P. and Lehman Brothers Inc. and Wachovia Capital Markets, LLC as representatives of the several underwriters, heretofore filed as Exhibit 10.1 to the Trust's current report on Form 8-K to the Securities and Exchange Commission filed on December 19, 2005, is incorporated herein by reference.*
- (b) Underwriting Agreement dated August 2, 2005 among the Permian Basin Royalty Trust, Burlington Resources, Inc., Burlington Resources Oil & Gas L.P. and Goldman Sachs & Co. and Lehman Brothers Inc. as representatives of the several underwriters, heretofore filed as Exhibit 10.1 to the Trust's current report on Form 8-K to the Securities and Exchange Commission filed on August 8, 2005, is incorporated herein by reference.*

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Exhibit

Number	Exhibit
(c)	<u>Underwriting Agreement dated August 17, 2006, among Permian Basin Royalty Trust, ConocoPhillips, Burlington Resources Oil & Gas Company LP and Lehman Brothers Inc. and Wachovia Capital Markets, LLC as representatives of the several underwriters heretofore filed as Exhibit 10.1 to the Trust's current report on Form 8-K to the Securities and Exchange Commission filed on August 22, 2006, is incorporated herein by reference.*</u>
(d)	<u>Registration Rights Agreement dated as of July 21, 2004 by and between Burlington Resources, Inc. and Bank of America, N.A., as trustee of Permian Basin Royalty Trust, heretofore filed as Exhibit 10.1 to the Trust's Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarterly period ended June 30, 2004 is incorporated herein by reference.*</u>
(23.1)	<u>Consent of Cawley, Gillespie & Associates, Inc., reservoir engineer.**</u>
(31.1)	<u>Certification required by Rule 13a-14(a)/15d-14(a).**</u>
(32.1)	<u>Certification required by Rule 13a-14(b)/15d-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.**</u>
(99.1)	<u>Report of Cawley, Gillespie & Associates, Inc., reservoir engineer.**</u>

* A copy of this Exhibit is available to any Unit holder, at the actual cost of reproduction, upon written request to the Trustee, Simmons Bank, 2911 Turtle Creek Boulevard, Suite 850, Dallas, Texas 75219.

** Filed herewith.

(P) Paper exhibits.

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SIGNATURE

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.

SIMMONS BANK,
TRUSTEE FOR THE
PERMIAN BASIN ROYALTY TRUST

By: /s/ RON E. HOOPER
Ron E. Hooper

SVP Royalty Trust Management

Date: March 18, 2019

(The Trust has no directors or executive officers.)