

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

(Amendment No. 1)

(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, 2025

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
Incorporation or Organization)

75-6280532

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

Argent Trust Company

3838 Oak Lawn Ave

Suite 1720

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	Trading Symbol	Name of Each Exchange on Which Registered
Units of Beneficial Interest	PBT	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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 USC. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

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 \$430,646,844.

At March 27, 2026, there were 46,608,796 Units of Beneficial Interest of the Trust outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

EXPLANATORY NOTE

Permian Basin Royalty Trust (the “Trust”) is filing this Amendment No. 1 on Form 10-K/A (the “Amended 10-K”) to amend the Company’s Annual Report on Form 10-K for the fiscal year ended December 31, 2025 (the “Original 10-K”), originally filed with the Securities and Exchange Commission (the “SEC”) on March 27, 2026, to amend certain disclosures in (i) *Item 2. Properties*, under the headings “Oil and Gas Production” and “Oil and Gas Reserves”, (ii) *Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations*, under the heading “Results of Operations”, and (iii) *Item 8. Financial Statements and Supplementary Data, Notes to Financial Statements* under “Note 6. to the Financial Statements, Supplemental Oil and Gas Reserve Information (Unaudited)”.

Except as described above, no other amendments are being made to the Original 10-K. This Amended 10-K does not reflect events occurring after the filing of the Original 10-K or modify or update the disclosure contained therein in any way other than as required to reflect the amendments discussed above.

The Trust has attached to this Amended 10-K updated certifications executed as of the date of this Amended 10-K by the Trustee as required by Sections 302 and 906 of the Sarbanes Oxley Act of 2002. These updated certifications are attached as Exhibits 31.1 and 32.1 to this Amended 10-K. An updated consent from the reserve engineering firm, Cawley, Gillespie & Associates, Inc. is attached as Exhibit 23.1 to this Amended 10-K.

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, regulatory matters, and actions by Unit holders seeking to judicially modify the Trust indenture and/or convert the Trust into a different investment vehicle. 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 future 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. Argent Trust Company, a Tennessee chartered trust company (“Argent”), is the current Trustee of the Trust. The principal office of the Trust (sometimes referred to herein as the “Registrant”) is located at 3838 Oak Lawn Ave, Suite 1720, Dallas, Texas (telephone number (855) 588-7839).

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 are 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.

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 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) 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 both became wholly-owned subsidiaries of ConocoPhillips.

BROG notified the Trust, that on November 1, 2019, the Waddell Ranch properties (as defined herein) that are subject to the Net Overriding Royalty Conveyance (Permian Basin Royalty Trust — Waddell Ranch) dated November 1, 1980 (the “Waddell Ranch Conveyance”), were sold to Blackbeard Operating, LLC (“Blackbeard”) of Fort Worth, Texas. Blackbeard became the operator effective as of April 1, 2020.

The term “net proceeds” is used in the above described conveyance and means the excess of “gross proceeds” received by the owner of the Underlying Properties during a particular period over “production costs” for such period. “Gross proceeds” means the amount received by the 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, the owner of the Underlying Properties 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. The owner of the Underlying Properties also has the obligation to maintain books and records sufficient to determine the amounts payable to the Trustee. The owner of the Underlying Properties, however, can sell its interests in the Underlying Properties.

Beginning in May 2024, proceeds from Blackbeard are received by the Trustee generally in the second month after production, but after the deadline to notify the New York Stock Exchange ("NYSE") of the current month distribution have passed. These funds are held for future distribution in the third month's distribution calculation and distributed in the fourth month such that reporting and distribution of funds are one month in arrears. 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.

Trustee Background

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.

On November 4, 2021, Simmons Bank announced that it had entered into an agreement with Argent pursuant to which Simmons Bank would be resigning as trustee of the Trust and would nominate Argent as successor trustee of the Trust. The effective date of Simmons Bank's resignation and Argent's appointment as successor trustee was December 30, 2022. The defined term "Trustee" as used herein shall refer to Bank of America N.A. for periods prior to August 29, 2014, shall refer to Southwest Bank for periods from August 29, 2014 through February 19, 2018, shall refer to Simmons Bank for periods from February 20, 2018 through December 29, 2022, and shall refer to Argent for periods on and after December 30, 2022.

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 U.S. Securities and Exchange Commission ("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. Argent Trust Company, EIN: 62-1437218, 3838 Oak Lawn Ave, Suite 1720, 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 Internal Revenue Service “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 income and monthly distributions are heavily influenced by commodity prices. Commodity prices may fluctuate widely in response to (i) relatively minor changes in the supply of and demand for oil and natural gas, (ii) market uncertainty and (iii) a variety of additional factors that are beyond the Trustee’s control. As of March 16, 2026, the price of oil was \$93.39 per barrel and the price of natural gas was \$3.03 per million British thermal units (“MMBtu”). Factors that may impact future commodity prices, including the price of oil and natural gas, include but are not limited to:

- political conditions in major oil producing regions, including the conflicts in Eastern Europe, the Middle East, and South America;
- worldwide economic and geopolitical conditions;
- weather conditions;
- trade barriers and tariffs;
- public health concerns, such as COVID-19;
- the supply and price of domestic and foreign crude oil or natural gas;
- the level of consumer demand;
- the price and availability of and purchaser or consumer preference for alternative fuels;
- the proximity to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures and governmental policies and regulatory incentives for investments in non-fossil fuel energy sources; and
- the nature and extent of governmental regulation and taxation.

Although the Trustee cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, gas royalty income for a given period generally relates to production three months prior to the period and crude oil royalty income for a given period generally relates to production two months prior to the period and will generally approximate current market prices in the geographic region of the production at the time of production. When crude oil and natural gas prices decline, the Trust is affected in two ways. First, distributable income from the Underlying Properties is reduced. Second, exploration and development activity by operators 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.

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 2026 net proceeds could increase compared to the electrical costs incurred during 2025 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 2026 net proceeds below the level that would exist if such costs remained at the level experienced in 2025. 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.

Proposed actions by certain Unit holders may have the effect of converting the Trust into a different type of investment, terminating the Trust, and/or permitting other changes to the Trust to occur that may not be acceptable to all Unit holders.

SoftVest, L.P., a Unit holder of the Trust, has a petition pending in District Court in Tarrant County, Texas, seeking to judicially modify the Trust indenture to eliminate certain supermajority voting requirements and prohibited amendments to the indenture. If SoftVest, L.P.'s petition is successful, the effect of such modification would be that any provision of the indenture could be amended by a majority in interest of Unit holders constituting a quorum at a meeting of Unit holders where a quorum is present. While providing greater flexibility to make changes that a majority of Units represented at a meeting are in support of, such a modification could have the result of permitting changes to be made to the Trust that holders of a majority of all outstanding Units are not actually in favor of. SoftVest has stated in documents filed with the SEC that if the judicial modification is successful, it believes the Trust should be converted into a publicly traded corporation or limited liability company to be effected by means of (a) the transfer of the Trust's assets to a newly-formed corporation or limited liability company ("Newco"), (b) the subsequent distribution of Newco's equity interests to Unit holders and (c) the termination of the Trust. SoftVest has stated that the proposed conversion would terminate the Trust's status as a fixed investment trust that is taxed as a grantor trust for federal income tax purposes, and that Newco would be subject to tax at the entity level if it is a corporation (unlike a grantor trust that is not subject to tax at the Trust level). SoftVest also noted that Newco could be a limited liability company treated as a partnership for federal income tax purposes, which would not be subject to tax at the entity level. Any modifications to the Trust's classification for federal (and applicable state and local) income tax purposes would result in additional costs incurred by the Trust to implement and maintain new reporting procedures, which could result in reduced distributions to Unit holders. Additionally, other changes could be made to the Trust indenture that currently require a supermajority vote, or are prohibited, including ceasing distributions, distributing the Royalties in kind, altering the rights of Unit holders vis-à-vis each other, changing the purpose of the Trust, selling the assets of the Trust, or terminating the Trust. Any or all of these changes may not be acceptable to all Unit holders.

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.

Blackbeard does not provide any forward looking information regarding future-development and capital expenditures such that the reserve estimates as of December 31, 2024 and forward exclude all proved undeveloped reserves ("PUDs"). SEC rules, subject to limited exceptions, permit PUDs to be disclosed only if they relate to wells scheduled to be drilled within five years after the date of disclosure. Without a development plan reflecting development of wells, the Trust cannot disclose PUDs from the Waddell Ranch properties.

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.

The assets of the Trust are depleting assets and, if the 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 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. Blackbeard has refused to provide its future development plans of the Underlying Properties to the Trustee.

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.

Government action, policies or regulations designed to discourage production of, reduce demand for, or promote alternatives to oil and natural gas could impact the price of oil and natural gas produced on the Underlying Properties, directly as intended or through unintended consequences.

Governments around the world are considering actions intended to reduce greenhouse gas emissions by decreasing both the supply of and the demand for oil and natural gas products or by promoting alternatives. These include the adoption of cap and trade regimes, carbon taxes, trade tariffs, minimum renewable usage requirements, restrictive permitting, increased mileage and other efficiency standards, mandates for sales of electric vehicles, mandates for use of specific fuels or technologies, and other incentives or mandates designed to support transitioning to lower-emission energy sources. Political and other actors and their agents also increasingly seek to advance climate change objectives indirectly, such as by seeking to reduce the availability or increase the cost of financing and investment in the oil and gas sector. Depending on how policies are formulated and applied, such policies could impact the ability and costs of the operators of the Underlying Properties to supply products, demand for their products, or the competitiveness of hydrocarbon-based products, which in turn, could reduce royalty income to the Trust. Any policy that increases the costs for operators of the Underlying Properties or decreases market prices could have a material impact on the distributable income of the Trust.

The Trustee may be subject to attempted cybersecurity disruptions from a variety of sources including state-sponsored actors.

The Trustee maintains robust cybersecurity protocols including, but not limited to technological capabilities that prevent and detect disruptions; computer workstations and programs protected with passwords and passphrases, as well as employee training throughout the year on financial regulations and cybersecurity followed up by testing of that knowledge. Other, non-technical protocols include securing of documents and work areas that could contain personal, non-public information and independent verification of information changes by outside vendors. If the measures taken to protect against cybersecurity disruptions prove to be insufficient or if proprietary data is otherwise not protected, the Trustee, or customer, employees, or third parties could be adversely affected. The Trust is also exposed to potential harm from cybersecurity events that may affect the operations of third-parties, including suppliers, service providers (including providers of cloud-hosting services for our data or applications), and customers. Cybersecurity disruptions could cause physical harm to people or the environment, damage or destroy assets; compromise business systems; result in proprietary information being altered, lost, or stolen; result in employee, customer, or third-party information being compromised; or otherwise disrupt business operations. The Trust could incur significant costs to remedy the effects of a major cybersecurity disruption in addition to costs in connection with resulting regulatory actions, litigations, or reputational harm.

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, damage to the environment or natural resources, or cleanup or remediation 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 of December 31, 2023, oil and gas production from the Waddell Ranch properties was processed through two facilities. Blackbeard has refused to verify if this information is still accurate as of December 31, 2024 and 2025. Should this number still be accurate, the limited number of gas processing facilities for the Waddell Ranch properties may impact future distributions from those properties as they may be particularly susceptible to operational risks and hazards. For example, a partial or complete shut down of 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 Blackbeard is the current operator of record of the properties burdened by the Waddell Ranch overriding royalty interests, none of the Trustee, the Unit holders or Blackbeard, as the current operator, has an operating interest in the properties burdened by the Texas Royalty properties' (as defined herein) 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.

Increased concerns about climate change and environmental sustainability could have an impact on development of the Underlying Properties.

There is considerable debate as to the environmental effects of greenhouse gas emissions and associated consequences affecting global climate, oceans, and ecosystems. We are not in a position to validate or repudiate the existence of climate change or various aspects of the scientific debate. However, climate change could have an impact on the operation of the Underlying Properties. Underlying Properties in areas with limited water availability may be particularly impacted if droughts become more frequent or severe. Similarly, more extreme weather events such as ice storms or extended periods of freezing or high temperatures could disrupt operation and production of the Underlying Properties. Changes in climate or weather may hinder exploration and production activities or increase or decrease the cost of production of oil and natural gas resources and consequently affect demand. Changes in climate or weather may also affect consumer demand for energy or alter the overall energy mix. However, we are not in a position to predict the precise effects of climate change on energy markets or the physical effects of climate change. We are providing this disclosure based on publicly available information on the matter.

It should be noted that, recently, concerns about the potential effects of climate change have resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. These concerns have also led to the oil and gas industry facing growing demand for corporate transparency and a demonstrated commitment to sustainability goals. Furthermore, in March 2024 the U.S. Securities and Exchange Commission ("SEC") adopted rule amendments that would require public companies to disclose certain climate-related information in their public filings. The new rules also required certain disclosure requirements related to severe weather events and other natural conditions in a company's audited financial statements. However, the SEC stayed implementation of the rules until legal challenges to the rules could be resolved, and following installation of the second Trump presidential administration, is reassessing its position in the litigation. Accordingly, the SEC rules have not yet gone into effect. Environmental, social, and governance ("ESG") goals and programs, which typically include extralegal targets related to environmental stewardship, social responsibility, and corporate governance, have also become an increasing focus of investors and

shareholders across the industry. While reporting on ESG metrics remains voluntary in the U.S., access to capital and investors is likely to favor companies with robust ESG programs in place. If participation in these initiatives becomes more common across the industry or if the rulemakings are ultimately reinstated or amended to require ESG-related disclosures, they could increase operational costs and make it more difficult for companies, including the companies that operate the Underlying Properties, to secure funding for exploration and production activities.

From a global perspective, the International Energy Agency (“IEA”) observed in its World Energy Outlook 2025 that global electricity demand continued to grow in 2024 and all energy sources, including renewable power and each of the fossil fuels, grew to meet that demand, which stemmed from emerging market and developing economies. Renewable power generation constituted 70% of the energy sources that met that demand and renewables grow faster than any other energy source in each of the IEA World Outlook current policies, stated policies, net zero emissions by 2050, and accelerating clean cooking and electricity services scenarios. The IEA notes the uncertainty in the energy sector related to global policy and trade and the value of energy supply diversification and supply chain resilience, particularly in light of increased geopolitical competition and conflict. In the last year, the U.S. has diminished its backing of wind, solar and electric vehicles, and increased its support of domestic fossil fuels and nuclear energy. Further, while the IEA noted an increase in the number of countries adopting renewable energy policies and energy performance standards, including vehicle fuel economy standards and energy performance standards for appliances and industrial motors, in the 2010s, those adoptions have somewhat flattened during the 2020s. The IEA also indicates momentum for national and international efforts to reduce emissions appears to have slowed. With the increase in geopolitical uncertainty and current energy market volatility, countries feeling vulnerable are increasingly focusing on enhancing their energy security policies, such as emergency stock oil requirements. The adoption and implementation of any international, federal, or state GHG-emission reduction commitments, legislation or regulations or other restrictions or imposition of taxes, fees, or limits on emissions of GHGs could result in increased development, operation, and compliance costs, additional operating restrictions on the Underlying Properties, and additional regulatory burdens, and thus decrease revenue to the Trust.

Terrorism, continued hostilities in Eastern Europe, the Middle East, and South America or other military campaigns 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 military or other actions taken in response, cause instability in the global financial and energy markets. Terrorism, continued hostilities in Eastern Europe, the Middle East, or South America or other 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 Units may lose value and cash available for distribution may be reduced as a result of title deficiencies with respect to the Royalty Properties.

The existence of a title deficiency with respect to any of the Royalty Properties could reduce the value or render a property worthless, thus adversely affecting the distributions to Unit holders. An operator’s inability or failure to cure title defects could cause the operator to lose its rights to some or all production from some of the Royalty Properties, which could result in a reduction in proceeds available for distribution to Unit holders and the value of the Units may be reduced.

Changes in the information historically made available to the Trustee by Blackbeard has delayed and will continue to delay Trust distributions

Since May 2024, Blackbeard has provided the Trustee information necessary to calculate the monthly net proceeds from the Waddell Ranch properties after the NYSE notification date for each monthly distribution. As a result, distribution of net proceeds from the Waddell Ranch properties each month has been delayed by a month such that distribution and reporting of distributions will remain one month in arrears.

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. Blackbeard is currently 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 Blackbeard in the current case of the Waddell Ranch properties (as defined herein), 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 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, Unit holders will realize gain or loss equal to the difference between the amount realized on the sale and termination of the Trust and their 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 5 and Note 8 to the Trust's financial statements, which are included herein. Each Unit holder should consult his, her or its 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 Blackbeard, 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 Blackbeard, 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 (“GAAP”). Although this basis of accounting is permitted for royalty trusts by the SEC, the financial statements of the Trust differ from GAAP financial statements mainly 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 recorded in GAAP financial statements. Further, Trust expenses are recorded when paid and not in the month they were incurred.

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 known as the Tax Cuts and Jobs Act (the “TCJA”) was enacted December 22, 2017, and made 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. Additionally, the One Big Beautiful Bill Act (“OBBA”) was signed into law on July 4, 2025 and, among other items, made permanent, extended or modified certain provisions under the TCJA. The TCJA and OBBA are complex, thus, Unit holders should consult their tax advisor regarding the TCJA and OBBA and their effect on an investment in Trust Units.

Any modification to the U.S. federal income tax laws or interpretations thereof (including administrative guidance relating to the TCJA or OBBA) may be applied retroactively and could adversely affect the Trust’s 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 issued. Any such changes or interpretations could negatively impact the value of an investment in the Trust Units.

Pandemics or other public health concerns, such as COVID-19, or the novel coronavirus, and any measures taken to mitigate such health concerns, could adversely affect the business and operations of the operators of the Waddell Ranch properties and the Texas Royalty properties, which in turn could have an adverse effect on Trust distributions.

Demand for oil and gas, and the business and operations of the operators of the properties underlying the net profits interests, had and may in the future be adversely impacted by public health concerns such as the COVID-19 pandemic and measures taken to mitigate its impact. The industry experienced a sharp and rapid decline in the demand for crude oil and natural gas as the U.S. and global economy in 2020, and commodity prices were negatively impacted as economic activity was curtailed in response to the COVID-19 pandemic, as well as due to other geopolitical factors. Future pandemics or other significant public health events could have a material adverse effect on the operators’ business and financial condition which would likely have an adverse effect on trust distributions.

Item 1B. Unresolved Staff Comments

The Trust has not received any written comments from the SEC staff regarding its periodic or current reports under the Act not less than 180 days before December 31, 2025, which comments remain unresolved.

Item 1C. Cybersecurity.

The Trust does not have a board of directors; therefore, the Trustee is responsible for oversight of the Trust’s risks from cybersecurity threats. The Trustee has dedicated personnel responsible for assessing and managing the Trust’s cyber risk management program, informing senior management of the Trustee regarding the prevention, detection, mitigation, and remediation of cybersecurity

incidents and supervising such efforts. The Trustee's information technology team has decades of experience selecting, deploying, and operating cybersecurity technologies, initiatives, and processes, and relies on threat intelligence as well as other information obtained from governmental, public or private sources, including external consultants engaged by the Trustee to monitor the prevention, detection, mitigation, and remediation of cybersecurity incidents. External partners are a key part of the Trustee's cybersecurity protocols and policies. The Trustee works with leading firms in the cybersecurity industry, leveraging their technology and expertise to monitor and maintain the performance and effectiveness of products and services that are used by the Trustee.

The Trustee maintains a cyber risk management program designed to identify, assess, manage, mitigate, and respond to cybersecurity threats, which processes are integrated into the Trustee's overall risk management process. The Trustee maintains robust cybersecurity protocols including, but not limited to technological capabilities that prevent and detect disruptions; computer workstations and programs protected with passwords and passphrases, as well as employee training throughout the year on financial regulations and cybersecurity followed up by testing of that knowledge. The protocols are based on recognized best practices and standards for cybersecurity and information technology. The Trustee has an annual assessment, performed by a third party vendor, of the Trustee's cyber risk management program.

Other non-technical protocols include securing of documents and work areas that could contain personal, non-public information and independent verification of information changes by outside vendors.

The Trust faces risks from cybersecurity threats that could have a material adverse effect on its business, financial condition, results of operations, cash flows or reputation. The Trustee has experienced, and will continue to experience, cyber incidents in the normal course of its business. However, prior cybersecurity incidents have not had a material adverse effect on the Trust's business, financial condition, results of operations, or cash flows. See Item 1A "Risk Factors."

Item 2. Properties

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 the owner of the Underlying Properties (from which the Royalties were carved) in the "gross" wells and acres.

The following information under this Item 2 is based upon data and information, including computation statements, furnished to the Trustee by Blackbeard, the operator of the Waddell Ranch properties, and Riverhill Energy, the operator of the Texas Royalty properties.

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 as of December 31, 2023, the most recent date for which the Trustee has information. A majority of the proved reserves are attributable to two fields, the Sand Hills and Waddell. There are 12 producing zones in these fields, and horizontal wells have been drilled in 11 of these zones over the past four years.

Proved reserves and estimated future net revenues attributable to the properties are included in the reserve reports summarized below. The owner of the Underlying Properties for Waddell Ranch 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 the owner of the Underlying Properties. In addition, implementation of any development programs will be dependent upon certain factors including, but not limited to, oil and gas prices currently being received and anticipated to be received in the future, along with the development plans of the operators and owners of the Underlying Properties.

Development information for the Waddell Ranch properties such as well completions, workovers, remedial activities, and plugging and abandonment, is not provided by Blackbeard.

Based on the quarterly reports provided by Blackbeard, the total amount of capital expenditures reported for the months of December 2024 through November of 2025 with regard to the Waddell Ranch properties totaled \$228.7 million (gross). Capital

expenditures do not include the cost of remedial and maintenance activities. The amount spent on remedial and maintenance activities was approximately \$21 million for the 12 months included in the 2025 quarterly reports.

The Trustee has been advised that, effective November 1, 2019, BROG sold its interests in the Waddell Ranch properties to Blackbeard. In conjunction with the transfer and assignment of the Waddell Ranch properties, BROG also assigned to Blackbeard all of its rights, title and interest in and to the Net Overriding Royalty Conveyance (Permian Basin Royalty Trust - Waddell Ranch) dated November 1, 1980. BROG handled all operations and accounting on behalf of Blackbeard until March 31, 2020.

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 35% 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”). 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.

Well Count and Acreage Summary. Information regarding the gross and net producing oil and gas wells and acres for the Blackbeard interests on the Waddell Ranch and Riverhill Energy’s interest in the Texas Royalty properties as of December 31, 2025 is not available.

OIL AND GAS PRODUCTION

The Trust recognizes production during the month in which the related distribution is received. As of May 2024, Blackbeard no longer provides the Trustee information necessary to calculate the net proceeds as of the NYSE notification date for the monthly distribution, such that oil and gas production for the calendar year 2024 is associated with actual production for 11 months from November 2023 through September 2024 and oil and gas production for the calendar year 2025 is associated with actual production for the 12 months of October 2024 through September 2025. Production for the Texas Royalty Properties is for the 12 months from November of the prior year through October of the current year for both 2024 and 2025. 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, 2025, excluding portions attributable to the adjustments discussed above, were as follows:

	Waddell Ranch Properties			Texas Royalty Properties			Total		
	2025	2024	2023	2025	2024	2023	2025	2024	2023
Royalties:									
Production									
Oil (barrels)	3,264,554	2,030,905	2,086,029	168,096	183,208	191,278	3,432,650	2,214,113	2,277,307
Gas (Mcf)	15,425,945	12,120,840	11,949,062	114,853	80,152	225,634	15,540,798	12,200,992	12,174,696
Underlying Properties:									
Production									
Oil (barrels)	4,352,738	2,707,874	2,781,372	190,875	205,201	213,525	4,543,613	2,913,075	2,994,897
Gas (Mcf)	20,567,926	16,161,120	15,932,082	130,420	89,765	251,846	20,698,346	16,250,885	16,183,928
Average Sales Price									
Oil/barrel	\$ 65.92	\$ 76.00	\$ 76.71	\$ 66.50	\$ 76.66	\$ 76.91	\$ 65.95	\$ 76.04	\$ 76.72
Gas/Mcf	\$ 1.74	\$ 1.40	\$ 2.37	\$ 8.77	\$ 9.94	\$ 4.60	\$ 1.78	\$ 1.45	\$ 2.40
Average Production Cost									
Oil/Gas BOE	\$ 18.54	\$ 21.39	\$ 20.59	\$ 7.87	\$ 7.90	\$ 6.95	\$ 18.26	\$ 20.86	\$ 19.98

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 increased to \$98 million (gross) in 2025 from \$82 million (gross) for 2024. Lease operating expenses for 2023 were \$80 million. A reason for the increase was not provided by Blackbeard. Waddell Ranch lifting cost on a barrel of oil equivalent (“BOE”) basis in 2025 was \$18.54 per barrel (“bbl”) as compared to \$21.39 per bbl in 2024 and \$20.59 in 2023. Gas volumes, reported in thousand cubic feet (“Mcf”), are converted to equivalent BOE at a ratio of six Mcf of gas to one bbl of oil.

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 previously been advised by the operator that the majority of oil from the Waddell Ranch was pipeline connected and sold under long term crude purchase agreements. Blackbeard did not confirm whether this continues to be the case as of December 31, 2025.

Gas. The trustee has previously been advised by the operator that the majority of gas produced from Waddell Ranch properties was processed through Targa Resources Corporation Midway processing plant. Both residue gas and plant products were purchased by Targa who received fees (gathering, compression, treating, processing) and a percentage of the gas and liquids as compensation. Blackbeard did not confirm whether this continues to be the case as of December 31, 2025.

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 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%.

“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.

Blackbeard does not provide a development budget or any forwarding looking information. As a result, in contrast to prior years, the reserve estimates as of December 31, 2024 and December 31, 2025, exclude all proved undeveloped reserves due to lack of a development plan reflecting wells to be drilled. In 2023, the last year for which development plan information was available, the proved undeveloped reserves constituted 48.3% of the total proved reserves for the Waddell Ranch properties and 38% of the total proved reserves for the Trust.

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, which are reviewed annually and updated as required, and the Trust reviews the reserve reports prepared by Cawley, Gillespie & Associates, Inc. ("CG&A"). 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 CG&A 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 Trustee does not have an internal petroleum engineer or petroleum engineering department and depends on CG&A to provide information regarding oil and gas reserves. 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 prepared by CG&A, whose firm registration number is F-693, was founded in 1961 and is nationally recognized in the evaluation of oil and natural gas properties. The technical person at CG&A primarily responsible for overseeing the reserves estimates with respect to the Trust is Zane Meekins. Mr. Meekins has been a practicing petroleum engineering consultant since 1989 with over 37 years of practice experience in petroleum engineering and is a registered professional engineer in the State of Texas (License No. 71055). Mr. Meekins graduated from Texas A&M University in 1987, *Summa Cum Laude*, with a B.S. degree in Petroleum Engineering. Both CG&A and Mr. Meekins have indicated that they meet or exceed all requirements set forth in Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

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 December 31, 2022 through December 31, 2025 (in thousands):

	Waddell Ranch Properties		Texas Royalty Properties		Total		
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	BOE
December 31, 2022	8,893	24,417	2,660	1,321	11,553	25,737	15,843
Extensions, discoveries, and other additions	4,504	8,064	—	—	4,504	8,064	5,848
Revisions of previous estimates	(2,137)	5,084	20	2,052	(2,118)	7,137	(929)
Production	(2,086)	(11,949)	(191)	(226)	(2,277)	(12,175)	(4,306)
December 31, 2023	9,174	25,616	2,489	3,147	11,662	28,763	16,456
Extensions, discoveries, and other additions	2,213	6,195	—	—	2,213	6,195	3,245
Revisions of previous estimates	(3,449)	2,311	154	(1,852)	(3,293)	460	(3,216)
Production	(2,031)	(12,121)	(183)	(80)	(2,214)	(12,201)	(4,248)
December 31, 2024	5,907	22,001	2,460	1,215	8,368	23,217	12,237
Extensions, discoveries, and other additions	4,886	12,148	—	—	4,886	12,148	6,911
Revisions of previous estimates	3,405	17,631	159	250	3,563	17,881	6,543
Production	(3,265)	(15,426)	(168)	(115)	(3,433)	(15,541)	(6,023)
December 31, 2025	10,933	36,354	2,451	1,350	13,384	37,705	19,668

Revisions to proved reserve volumes in each year were primarily attributable to changes in commodity prices and variations in the performance of the underlying net profits interests relative to the prior year reserve report. The performance-related revisions reflect several factors, including the level of development activity, production volumes, and development costs associated with the net profits interests.

- For the year ended December 31, 2025, revisions increased proved reserves primarily as a result of improved performance of the net profits interests, associated with significant development activity at the Waddell Ranch, which increased reserve volumes by 7,582 thousand barrels of oil equivalent ("MBOE"). This favorable impact was partially offset by lower commodity prices, which reduced reserve volumes by 1,039 MBOE.
- For the year ended December 31, 2024, proved reserve quantities were revised downward primarily due to lower performance of the net profits interests, resulting in a decrease of 3,104 MBOE, together with the effect of lower commodity prices, which reduced reserve volumes by 112 MBOE.
- For the year ended December 31, 2023, revisions to proved reserve quantities were primarily attributable to lower commodity prices, which reduced reserve volumes by 4,904 MBOE. This decrease was partially offset by improved performance of the net profits interests, which increased reserve volumes by 3,975 MBOE.

Estimated quantities of proved reserves and net cash flow as of December 31, 2025 are as follows (in thousands):

Waddell Ranch Properties				
	Oil (Bbls)	Gas (Mcf)	BOE	10% Disc. Cash Flow, \$
Proved Developed Producing	10,933	36,354	16,992	\$ 766,496
Proved Developed	10,933	36,354	16,992	\$ 766,496
Total Proved	10,933	36,354	16,992	\$ 766,496

Texas Royalty Properties				
	Oil (Bbls)	Gas (Mcf)	BOE	10% Disc. Cash Flow, \$
Proved Developed Producing	2,451	1,350	2,676	\$ 159,226
Proved Developed	2,451	1,350	2,676	\$ 159,226
Total Proved	2,451	1,350	2,676	\$ 159,226

Total Waddell Ranch Plus Texas Royalty Properties				
	Oil (Bbls)	Gas (Mcf)	BOE	10% Disc. Cash Flow, \$
Proved Developed Producing	13,384	37,705	19,668	\$ 925,721
Proved Developed	13,384	37,705	19,668	\$ 925,721
Total Proved	13,384	37,705	19,668	\$ 925,721

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

Proved Developed Reserves:	Oil (Bbls)	Gas (Mcf)	BOE
December 31, 2022	8,022	21,216	11,558
December 31, 2023	7,236	21,001	10,736
December 31, 2024	8,368	23,217	12,237
December 31, 2025	13,384	37,705	19,668

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

Proved Undeveloped Reserves:	Oil (Bbls)	Gas (Mcf)	BOE
December 31, 2022	3,531	4,521	4,284
December 31, 2023	4,427	7,762	5,720
December 31, 2024	—	—	—
December 31, 2025	—	—	—

The SEC 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 2025, 2024 and 2023 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		
	2025	2024	2023	2025	2024	2023	2025	2024	2023
January 1	\$ 292,782	\$ 426,341	\$ 579,453	\$ 78,584	\$ 82,208	\$ 107,013	\$ 371,366	\$ 508,548	\$ 686,467
Extensions, discoveries, and other additions	220,395	108,923	185,611	—	—	—	220,395	108,923	185,611
Accretion of discount	29,278	42,634	57,945	7,858	8,221	10,701	37,136	50,855	68,646
Revisions of previous estimates and other	(60,739)	(272,293)	(382,673)	(8,680)	2,295	(20,490)	(69,420)	(269,997)	(403,164)
Royalty income	—	(12,823)	(13,995)	(11,555)	(14,140)	(15,016)	(11,555)	(26,963)	(29,011)
December 31	<u>\$ 481,716</u>	<u>\$ 292,782</u>	<u>\$ 426,341</u>	<u>\$ 66,206</u>	<u>\$ 78,584</u>	<u>\$ 82,208</u>	<u>\$ 547,922</u>	<u>\$ 371,366</u>	<u>\$ 508,549</u>

Average oil and gas prices of \$65.34 per barrel and \$3.387 per Mcf, respectively, were used to determine the estimated future net revenues from the Waddell Ranch properties and the Texas Royalty properties at December 31, 2025. The increase in the discounted future net cash flows for the Waddell Ranch properties was primarily due to new drilling projects. The discounted future net cash flows for the Texas Royalty properties decreased primarily due to lower oil pricing.

Average oil and gas prices of \$75.48 per barrel and \$2.13 per Mcf, respectively, were used to determine the estimated future net revenues from the Waddell Ranch properties and the Texas Royalty properties at December 31, 2024. The decrease in discounted future net cash flows for the Waddell Ranch properties was primarily due to exclusion of proved undeveloped reserves and weaker pricing for oil and gas. The discounted future net cash flows for the Texas Royalty properties decreased due to weaker pricing for oil.

Average oil and gas prices of \$78.22 per barrel and \$2.64 per Mcf, respectively, were used to determine the estimated future net revenues from the Waddell Ranch properties and the Texas Royalty properties at December 31, 2023. The decrease in the discounted future net cash flows for the Waddell Ranch properties was primarily due to weaker pricing for oil and gas. Discounted future net cash flows for the Texas Royalty properties decreased primarily due to weaker pricing for oil.

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, 2025, 2024 and 2023 (in thousands):

	2025		2024		2023	
	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	\$ 766,496	\$ 481,716	\$ 460,094	\$ 292,782	\$ 707,043	\$ 426,341
Texas Royalty properties	159,226	66,206	183,558	78,584	190,372	82,208
Total	<u>\$ 925,721</u>	<u>\$ 547,922</u>	<u>\$ 643,652</u>	<u>\$ 371,366</u>	<u>\$ 897,415</u>	<u>\$ 508,549</u>

Reserve quantities and revenues shown in the preceding tables for the Royalties were estimated from projections of reserves and revenue attributable to the combined Blackbeard, Riverhill 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 exploration and 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 and regulate the flaring of natural gas and impose certain requirements regarding the ratability of 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.

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”). 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, number, operation of wells and the prevention of waste of oil and gas

resources, bonding or other financial assurance to drill or operate wells, decommissioning and removal of equipment, and the plugging and abandonment of wells. 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. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from the wells on the Underlying Properties, negatively affect the economics of production from these wells, or limit the number of wells or locations can be drilled.

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.

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 emitted or released into the environment; the limitation or prohibition of drilling or other construction or operational activities on certain lands lying within wilderness, wetlands, endangered or threatened species habitat, and other sensitive environments or protected areas; the installation of emission monitoring and/or pollution control equipment; the reporting of the types and quantities of various substances that are generated, stored, processed, released, or disposed of 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 sourcing and disposal of water used in the drilling, fracturing completion and production processes; 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 adverse modification, suspension or revocation of necessary permits, licenses and authorizations; the requirement that additional pollution controls be installed; the assessment of administrative, civil or criminal fines or penalties; the imposition of investigatory, ongoing monitoring, 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 drilling or other operations 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.

All of the jurisdictions in which the Underlying Properties are operated have statutory and administrative provisions regulating the exploration for and production of oil and natural gas, including, for example, provisions related to the sourcing and disposal of water used in the drilling and completion process, the control and permitting of air emissions from well completion and production operations, the management and disposal of wastes and wastewater (including produced water) generated from the operation of the Underlying Properties, decommissioning and removal of equipment, bonding to drill or operate wells, decommissioning and removal of equipment, and the plugging and abandonment of wells. Operation of the Underlying Properties is also subject to regulations that generally prohibit the venting or flaring of natural gas. The effect of such regulations may be to limit the amounts of oil and natural gas that may be produced from the wells on the Underlying Properties or negatively affect the economics of production from these wells.

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. The United States, depending on which President has been in office, has participated (during the Biden administration) or not (during the two Trump administrations) in the Paris Climate Accord, a voluntary international agreement with the goal of limiting global climate change to not more than 2 degrees Celsius (or less). The Biden administration had also set ambitious domestic targets for curbing climate change, such as making the U.S. power sector carbon-neutral by 2035 and announcing a plan to achieve net-zero emissions from overall federal operations by 2050. While changes in U.S. presidential administrations could increase or lessen the relative impacts of climate policies and regulations on the oil and natural gas industry, the adoption and implementation of any international, federal, or state greenhouse gas (“GHG”)–emission reduction commitments, legislation, or regulations or other restrictions or imposition of taxes, fees, or limits on emissions of GHGs could result in increased development, operation, and compliance costs, additional operating restrictions on the Underlying Properties, and additional regulatory burdens, and thus decrease revenue to the Trust.

In response to the April 2007 U.S. Supreme Court decision in *Massachusetts vs. EPA* finding that greenhouse gases (“GHGs”) are air pollutants under the Clean Air Act (“CAA”), the United States Environmental Protection Agency (the “EPA”) issued an “Endangerment Finding” under Section 202(a) of the CAA, concluding that GHG pollution threatens the public health and welfare of future generations. Thereafter, EPA promulgated GHG monitoring and reporting regulations (the “GHG Reporting Rule”) 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. The EPA indicated that it will use data collected through the reporting rules to decide whether to promulgate future GHG emission limits. In August 2022, Congress passed the Inflation Reduction Act, which included requirements to impose fees beginning in 2025 on 2024 calendar year methane emissions from oil and gas operations that are required to report their GHG emissions under the EPA’s GHG Reporting Rule. EPA’s final rule to implement the fee requirements, “Waste Emissions Charge for Petroleum and Natural Gas Systems” was published on November 18, 2024, and took effect on January 17, 2025. Compliance with these rules would have required enhanced record-keeping practices and, thus, may have increased operating costs associated with the Underlying Properties and may have decreased net revenue to the Trust. However, following the second Trump presidential inauguration, Congress postponed collection of the Waste Emissions Charge until 2034 under the One Big Beautiful Bill Act, which President Trump signed into law on July 4, 2025. And, consistent with that postponement, EPA proposed on September 12, 2025, to suspend all GHG reporting for the oil and gas sector (40 C.F.R. Part 98, Subpart W) until 2034. Further, on February 12, 2026, EPA rescinded the endangerment finding on the basis that EPA lacks statutory authority under Section 202(a) of the CAA to prescribe standards for GHG emissions, thus creating additional uncertainty about the scope and extent of GHG regulation in the United States. If the GHG reporting rule is not permanently repealed and if the rescission of the endangerment finding is not upheld in the litigation that promptly ensued, operating costs associated with GHG recordkeeping and reporting will continue to be incurred for the Royalty Properties. If GHG enhanced reporting, emission fees, reduction targets, or additional permitting are reinstated or imposed in the future, such requirements could decrease net revenue to the Trust.

In addition, on May 9, 2024, pursuant to its authority under Section 111 of the CAA to set emission standards for new and existing power plants based on the “best system of emission reduction,” EPA finalized new source performance standards for GHG emissions from fossil fuel-fired stationary combustion turbine electricity generating units and from certain fossil-fuel fired steam generating units. Among other requirements, the rule, effective July 8, 2024, revised CAA New Source Performance Standards (“NSPS”) for new or substantially modified natural gas-fired power plants based on the use of more efficient fuels, simple cycle operation, and the implementation of carbon capture and sequestration/storage technology. The rule also revises the NSPS for GHG emissions from fossil fuel-fired steam generating units that undertake major modifications. The rule was promptly challenged in court, and on June 11, 2025, EPA under the second Trump Administration proposed to repeal GHG emissions standards for fossil fuel-fired power plants and to make a finding that GHG emissions from fossil fuel-fired power plants do not contribute significantly to dangerous air pollution or, in the alternative, repeal certain other requirements, such as the emission guidelines for existing fossil fuel-fired steam generating units, and certain carbon capture and storage standards for coal-fired steam generating units and new base load stationary combustion turbines. Adoption of rules that either place additional limits on GHG emissions from fossil fuel-fired electricity or steam generating units or otherwise incentivize non-fossil fuel generated sources of energy could reduce demand for oil and gas generally, including oil and gas produced from the Royalty Properties and could increase the cost of operations of the Underlying Properties, which could result in a loss of reserves or revenues to the Trust.

Pursuant to the CAA and state laws concerning the permitting of air emissions, certain new and modified sources of air emissions are subject to air permitting authorizations for construction and operation, and sources of air emissions at the Underlying Properties are no exception to these requirements. In addition to air permitting requirements, certain sources of emissions involved in oil and gas operations are subject to source-specific emission standards pursuant to CAA New Source Performance Standards (“NSPS”) and National Emissions Standards for Hazardous Air Pollutants (“NESHAPs”). For example, on August 16, 2012, the EPA issued a final rule, known as NSPS Subpart OOOO, that established new source performance standards for volatile organic compounds (“VOCs”) 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 applied to certain oil and natural gas sources that were constructed, modified, or reconstructed after August 23, 2011, and required that 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 also has the co-benefit of limiting methane, a GHG. In addition, these regulations also include requirements applicable to storage tanks and other equipment in the affected oil and natural gas industry segments. On June 3, 2016, EPA promulgated NSPS Subpart OOOOa, 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 NSPS Subpart OOOOa rules, extended green completion requirements to new hydraulically fractured or refractured oil wells. Furthermore, in December 2023, EPA announced additional final NSPS OOOO program rules, referred to as Subparts OOOOb and OOOOc, which are expected to have a significant impact on the upstream and midstream oil and gas sectors from an operational cost perspective. The rules formally institute methane emissions limitations from new, modified, and reconstructed sources; and will regulate existing sources for the first time under the NSPS Subpart OOOOc program by requiring states to implement plans that meet or exceed federally established emission reduction guidelines for existing oil and natural gas facilities. Legal challenges, including by states, to the recently finalized NSPS Subparts OOOOb and OOOOc rules have ensued. Further, the EPA under the second

Trump Administration issued a Final Rule on December 3, 2025, extending certain OOOOb and OOOOc compliance deadlines. Thus, although the bulk of the 2012 and 2016 standards are currently in effect, future implementation and the ultimate scope of the VOC and methane emissions regulations for the oil and gas production, transmission, and storage industry segments are uncertain at this time as a result of recent rulemakings and ongoing and expected legal challenges.

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 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 into regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers (“USACE”). Whether CWA permitting is required depends upon whether and the extent to which “Waters of the United States” (“WOTUS” or “jurisdictional waters”) may be impacted by the planned activity—for example, construction of drilling pads, access roads, or pipelines. Rulemaking by EPA and the USACE to define WOTUS has been heavily litigated, resulting in the rule taking effect at times in some states but not others and creating definitions that are more inclusive of certain waters effective in some states and those that are less inclusive effective in other states. EPA and USACE’s WOTUS definition rulemaking published in the Federal Register on January 18, 2023 (the January 2023 Rule) incorporated “relatively permanent” and “significant nexus” standards for determining jurisdiction over adjacent wetlands and additional waters, expanding the types of waters that could be considered WOTUS; however, this WOTUS definition was litigated and eventually amended on August 29, 2023, when EPA and USACE issued a final rule to conform the WOTUS definition to the U.S. Supreme Court’s May 25, 2023 decision in *Sackett v. Environmental Protection Agency*, which invalidated parts of the January 2023 Rule. With the August 2023 rulemaking, EPA and USACE implemented a narrower definition of WOTUS by, for example, removing “interstate wetlands”; redefining “adjacent” to mean “having a continuous surface connection”; and removing the “significant nexus” standard from the provisions regarding tributaries, adjacent wetlands, and intrastate lakes and ponds. EPA’s November 17, 2025, proposed rule aims to further conform the WOTUS definition to the Sackett decision by providing additional definitions for “relatively permanent,” “tributary,” and “continuous surface connection,” as well as by introducing additional exclusions and revisions to others, including exclusions for groundwater (i.e., groundwater would not be considered WOTUS) and prior converted cropland, an attempt to clarify the exclusion for ditches, and a broader exclusion for wastewater treatment systems. Comments on the November 2025 proposal were due by January 5, 2026. Regardless, the applicable WOTUS definition affects what CWA permitting or other regulatory obligations, such as spill prevention, control, and countermeasure (“SPCC”) planning, 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.

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 fines and 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 or arranged for transport of 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. From time to time, EPA may designate additional materials as hazardous substances under CERCLA, which could result in additional investigation and remediation at current Superfund sites, or reopening of Superfund sites that previously received regulatory closure. For example, EPA issued a final rule that became effective July 8, 2024, designating as “hazardous substances” under CERCLA perfluorooctanoic acid (“PFOA”) and perfluorooctanesulfonic acid (“PFOS”), which have been commonly used in a variety of industrial and consumer products. 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 responsibility under CERCLA could be imposed 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 regard, hydrocarbons or other solid wastes (including hazardous or nonhazardous waste) 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. The federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976 (“RCRA”) and analogous state laws regulate the management and disposal of solid waste, including hazardous and nonhazardous waste. Although some wastes associated with the exploration and production of oil and natural gas are currently regulated as nonhazardous waste and are exempted from hazardous waste regulation under RCRA, this exemption is subject to being limited or lost, and the loss of this exemption would result in more stringent regulation of these types of waste. Moreover, these wastes and other wastes may be otherwise regulated by the EPA or state agencies. In addition, in the ordinary course of operation of the Underlying Properties, industrial wastes such as paint wastes and waste solvents may be regulated as hazardous waste under RCRA or considered hazardous substances under CERCLA. 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 analogous state programs regulate the drilling and operation of salt water disposal and injection 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 and injection 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 the potential seismic impacts of 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. Furthermore, in response to a number of earthquakes in recent years in the Midland Basin, the RRC announced in September 2021 that it will not issue any new saltwater disposal (“SWD”) well permits in an area known as the Gardendale Seismic Response Area (“SRA”), and will require existing SWD wells in that area to reduce their maximum daily injection rate to 10,000 barrels per day per well. In December 2021, the RRC went on to suspend all well activity in deep formations in the Gardendale SRA, effectively terminating 33 disposal well permits. The RRC has since identified two additional SRAs; (the Northern Culberson-Reeves (“NCR”) SRA and the Stanton SRA), and required operators in the NCR and Stanton SRAs to develop and implement seismic response plans, (which include expanded data collection efforts, contingency responses for future seismicity, and scheduled checkpoint updates with RRC staff). In response to additional earthquakes in the area, the RRC suspended all (totaling 23) deep disposal well permits in the NCR SRA and proposed additional daily injection volume curtailments for the Stanton SRA. Such restrictions and requirements could limit the Underlying Properties’ oil and gas well exploration and production activities or increase the cost of those activities if wastewater disposal options become limited.

In addition, several cases have in recent years 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. In a statement issued by EPA in April 2019, the Agency concluded that the CWA should not be interpreted to require permits for discharges of pollutants that reach surface waters via groundwater. However, in April 2020, the Supreme Court issued a ruling in the case, *County of Maui, Hawaii v.*

Hawaii Wildlife Fund, holding that discharges into groundwater may be regulated under the CWA if the discharge is the “functional equivalent” of a direct discharge into navigable waters. In November 2023, EPA issued draft guidance outlining the factors that may be considered when evaluating whether discharges through groundwater may be the “functional equivalent” of a direct discharge and subject to regulation under the CWA National Pollutant Discharge Elimination System permitting program and describing the types of information that should be used in the determination. Comments on the draft guidance were due to the agency by December 27, 2023, and to date EPA has not yet finalized the guidance. If in the future CWA permitting is required for saltwater injection wells as a result of the Supreme Court’s ruling in *County of Maui, Hawaii v. Hawaii Wildlife Fund*, the costs of permitting and compliance for injection well operations by the companies that operate 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 Bald and Golden Eagle Protection 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 operators of the Underlying Properties are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes. In addition to the OSHA hazard communication standard, the EPA 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 also require disclosure of information about hazardous materials used, produced or otherwise managed during operation of the Underlying Properties. Some of 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; the effect that noncompliance with existing environmental laws, rules and regulations; compliance with new legislation or regulation, or enforcement policies thereunder; or claims for property or environmental damage, or for personal injury or death, resulting from operations on the Underlying Properties could have on the Trust or Trust distributions. Even if the Trust were not directly liable for costs or expenses related to these matters, 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 existing or new environmental legislation or regulation, decreases in the completion of new oil and natural gas wells, or an enforcement action or a private party action that could result in wells being plugged and abandoned earlier in their productive lives, resulting in a loss of reserves and revenues to the Trust 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

SoftVest Petition

On December 26, 2025, SoftVest, L.P. (“SoftVest”), a Unit holder of the Trust, filed an Original Petition for Modification of Trust (the “Petition”) in the District Court of Tarrant County, Texas (Cause No. 96-373245-25) seeking judicial modification of the Trust’s Indenture. In the Petition, SoftVest seeks to (1) amend Section 8.03 of the Indenture to eliminate the requirement that certain amendments require approval by 75% of the outstanding Units of the Trust, and (2) delete Section 10.01 of the Indenture that sets forth certain prohibited amendments and replace Article X of the Indenture with a provision permitting amendment of any provision of the Indenture by a vote of Unit holders in accordance with Article VIII (which, as amended, would permit amendment by a majority in interest of Unit holders constituting a quorum at a meeting of Unit holders where a quorum is present). A hearing on the Petition is scheduled for Friday, May 8, 2026 at 10:30 a.m.

Blackbeard Settlement

On August 19, 2025, the Trustee entered into a settlement agreement and release (the “Settlement Agreement”) in connection with its lawsuit against Blackbeard, as operator of the properties in the Waddell Ranch, in Crane County, Texas, in which the Trust holds a 75% net overriding royalty. Pursuant to the lawsuit, the Trustee had sought to recover more than \$9 million in damages it alleged resulted from Blackbeard’s failure to properly calculate and pay royalties due and owing to the Trust.

Pursuant to the Settlement Agreement, Blackbeard agreed to pay the Trust \$9,000,000, of which \$4,500,000 was paid to the Trust on September 18, 2025, and the remainder of which will be paid in four equal installments of \$1,125,000 quarterly during the 2026 calendar year.

Additionally, the Settlement Agreement established the overhead rate that may be charged to the Trust and permits Blackbeard to pass through third-party charges for salt water disposal, gathering and transportation, and charge technical labor on reservoir engineers using an agreed allocation methodology against the net overriding royalty. The parties also agreed that the Trust would not make future claims for lost volumes in the case of ordinary line loss (as defined by third party purchase agreements with purchasers). The Trust will have the option to conduct annual site audits, at its expense. The Settlement Agreement also set forth agreed reporting that Blackbeard will provide the Trustee going forward.

Except as described above, 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.

PART II

Item 5. Market for Units of the Trust, Related Security Holder Matters and Trust Purchases of Units

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 656 Unit holders of record held the 46,608,796 Units of the Trust at March 23, 2026.

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

Item 6. [Reserved]

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. The Waddell Ranch properties did not contribute to royalty income from October 2024 through December 31, 2025, and were in a deficit position as of December 31, 2025. Royalty income received by the Trust for the five years ended December 31, 2025, was computed as shown in the table on the next page.

Gross Proceeds of Sales From the Underlying Properties:	Year Ended December 31,									
	2025		2024		2023		2022		2021	
	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties	Texas Royalties Properties	Waddell Ranch Properties	Texas Royalty Properties
Oil Proceeds	\$ 286,941,425	\$ 12,692,579	\$ 205,785,388	\$ 15,730,975	\$ 213,356,229	\$ 16,423,167	\$ 195,554,348	\$ 20,665,465	\$ 66,328,817	\$ 12,799,649
Gas Proceeds	35,796,389	1,143,304	22,659,209	892,576	17,428,482	1,159,111	37,108,451	1,357,568	17,259,346	906,335
Other (adjustment) ⁽¹⁾	50,244,261	—	13,623,357	—	20,293,769	—	10,903,556	—	9,423,956	—
Total	372,982,075	13,835,883	242,067,954	16,623,551	251,078,480	17,582,278	243,566,355	22,023,033	93,012,119	13,705,984
Less:										
Severance Tax										
Oil	13,518,692	515,254	9,353,474	619,552	9,678,938	632,418	8,915,016	792,637	3,057,598	380,409
Gas	356,478	43,556	161,948	32,066	933,225	49,117	4,481,839	83,522	194,140	48,894
Gathering and Transportation Costs	32,437,258	153,598	23,864,405	127,292	21,715,807	134,222	\$ 15,427,633	—	173,640	—
Lease Operating Expense and Property tax:										
Oil and Gas	97,951,879	960,000	82,174,511	960,000	79,628,562	960,000	43,673,061	800,380	23,026,783	849,824
Capital Expenditures	228,717,768	—	109,416,344	—	120,462,603	—	124,283,888	—	66,559,957	—
Total	372,982,075	1,672,408	224,970,682	1,738,910	232,419,135	1,775,757	\$ 196,781,437	\$ 1,676,539	\$ 93,012,118	\$ 1,279,127
Net Profits	—	12,163,475	17,097,273	14,884,641	18,659,345	15,806,521	\$ 46,784,918	\$ 20,346,494	\$ —	\$ 12,426,857
Net Overriding Royalty Interest	75%	95%	75%	95%	75%	95%	75%	95%	75%	95%
Total Royalty Income for Distribution ⁽²⁾	\$ —	\$ 11,555,301	\$ 12,822,955	\$ 14,140,409	\$ 13,994,509	\$ 15,016,195	\$ 35,088,618	\$ 19,329,169	\$ —	\$ 11,805,514

(1) See Note 4 to Financial Statements under Item 8. Financial Statements and Supplemental Data

(2) Total Royalty Income for the Waddell Ranch properties does not include the \$4.5 million partial settlement payment received in September of 2025.

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, 2025

Recent Developments

SoftVest Special Meeting and Petition

On December 16, 2025, the Trust held a special meeting of its Unit holders (the “Special Meeting”). The Special Meeting was called by the Trustee as required by Section 8.02 of the Trust Indenture at the request of SoftVest Advisors, LLC (“SoftVest Advisors”) and other Unit holders of the Trust collectively owning not less than 15% of the outstanding Trust Units. At the Special Meeting, Unit holders approved a non-binding proposal for SoftVest Advisors or another appropriate party to take appropriate actions as beneficiaries of the Trust to effect the judicial reformation or modification of the Trust Indenture, to allow for the approval of any amendment to the Trust Indenture by a simple majority of votes cast by Unit holders at a special meeting at which a quorum is present.

On or about February 10, 2026, SoftVest, L.P. (“SoftVest”), a Unit holder of the Trust, mailed documents to the other Unit holders, which included a cover letter, a Citation in the District Court of Tarrant County, Texas (“Citation”), the Original Petition for Modification of Trust (the “Petition”) in the District Court of Tarrant County, Texas (Cause No. 96-373245-25) seeking judicial modification of the Trust’s Indenture, and the Petitioner SoftVest, L.P.’s Notice of Bench Trial on Petitioner’s Original Petition for Modification of Trust (“Notice of Bench Trial”), also collectively known as the “Unit holder Mailing”. The Unit holder Mailing advises Unit holders of a hearing to be scheduled Friday, May 8, 2026, at 10:30 a.m. before the 96th District Court of Tarrant County, Tom Vandergriff Civil Courts Building, 4th Floor, 100 North Calhoun Street, Fort Worth, Texas 76196, on the merits of SoftVest’s Petition pursuant to which it seeks to (1) amend Section 8.03 of the Indenture to eliminate the requirement that certain amendments require approval by 75% of the outstanding Units of the Trust, and (2) delete Section 10.01 of the Indenture that sets forth certain prohibited amendments and replace Article X of the Indenture with a provision permitting amendment of any provision of the Indenture by a vote of Unit holders in accordance with Article VIII (which, as amended, would permit amendment by a majority in interest of Unit holders constituting a quorum at a meeting of Unit holders where a quorum is present).

Blackbeard Settlement

On August 19, 2025, the Trustee entered into a settlement agreement and release (the “Settlement Agreement”) in connection with its lawsuit against Blackbeard, as operator of the properties in the Waddell Ranch, in Crane County, Texas, in which the Trust holds a 75% net overriding royalty. Pursuant to the lawsuit, the Trustee had sought to recover more than \$9 million in damages it alleged resulted from Blackbeard’s failure to properly calculate and pay royalties due and owing to the Trust.

Pursuant to the Settlement Agreement, Blackbeard agreed to pay the Trust \$9,000,000, of which \$4,500,000 was paid to the Trust on September 18, 2025, and the remainder of which will be paid in four equal installments of \$1,125,000 quarterly during the 2026 calendar year.

Additionally, the Settlement Agreement established the overhead rate that may be charged to the Trust and permits Blackbeard to pass through third-party charges for salt water disposal, gathering and transportation, and charge technical labor on reservoir engineers using an agreed allocation methodology against the net overriding royalty. The parties also agreed that the Trust would not make future claims for lost volumes in the case of ordinary line loss (as defined by third party purchase agreements with purchasers). The Trust will have the option to conduct annual site audits, at its expense. The Settlement Agreement also set forth agreed reporting that Blackbeard will provide the Trustee going forward.

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, 2025, which for 2025 is only from the Texas Royalty Properties, due to the excess cost position of the Waddell Ranch properties, is reported in the following table:

<u>Royalties</u>	<u>Year Ended December 31,</u>		
	<u>2025</u>	<u>2024</u>	<u>2023</u>
Total Royalty Income ⁽¹⁾	\$ 11,555,301	\$ 26,963,365	\$ 29,010,704
	100%	100%	100%
Oil Royalty Income	10,399,771	24,267,029	24,949,205
	90%	90%	86%
Gas Royalty Income	1,155,530	2,696,336	4,061,499
	10%	10%	14%
Total Royalty Income/Unit	\$ 0.247921	\$ 0.578504	\$ 0.622430

(1) Total Royalty Income for 2025 does not include the \$4.5 million partial payment of the lawsuit settlement paid to the Trust in September 2025 by Blackbeard.

As of May 2024, Blackbeard, the operator of the Waddell Ranch properties, provides the Trustee information necessary to calculate the net proceeds after the NYSE notification date such that royalty income of the Trust for the current calendar year is associated with actual oil and gas production for the period from October 2024 through September 2025 for the Waddell Ranch properties. Royalty income for the Trust for the calendar year for the Texas Royalty properties is associated with actual oil and gas production from November 2024 through October 2025. Oil and gas production for 2025, 2024 and 2023 generated by the Royalties and the Underlying Properties, excluding portions attributable to the adjustments discussed hereafter, are presented in the following table:

<u>Royalties</u>	<u>Year Ended December 31,</u>		
	<u>2025</u>	<u>2024</u>	<u>2023</u>
Oil Sales (Bbls)	3,432,650	2,214,113	2,277,307
Gas Sales (Mcf)	15,540,798	12,200,992	12,174,696
Underlying Properties			
Oil			
Total Oil Sales (Bbls)	4,543,613	2,913,075	2,994,897
Average Per Day (Bbls)	12,448	7,981	8,090
Average Price/Bbl	\$ 65.95	\$ 76.04	\$ 76.72
Gas			
Total Gas Sales (Mcf)	20,698,346	16,250,885	16,183,928
Average Per Day (Mcf)	56,708	44,523	44,340
Average Price/Mcf	\$ 1.78	\$ 1.45	\$ 2.40

The average price of oil decreased to \$65.95 per barrel in 2025, down from \$76.04 per barrel in 2024. The average price of oil in 2023 was \$76.72 per barrel. In addition, the average price of gas increased from \$1.45 per Mcf in 2024 to \$1.78 per Mcf in 2025. The average price of gas in 2023 was \$2.40 per Mcf. Oil prices have decreased primarily because of world market conditions. Oil prices are expected to remain volatile. Gas liquids values have declined due to high production levels, consistently mild weather patterns, and decreased heating demand. Blackbeard, after assuming the role of operator of the Waddell Ranch properties, immediately instituted a workover of specific wells, which caused the Trust not to receive any royalty income from the Waddell Ranch properties in portions of 2023 and 2024, and all of 2025. Royalty income was not received for the Waddell Ranch properties for the year 2025 due to large capital expenditures.

Subsequent to December 31, 2025, 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 March 16, 2026, NYMEX posted oil prices were approximately \$93.39 per barrel, which compared to the posted price of \$65.34 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 March 16, 2026, NYMEX posted gas prices were \$3.03 per MMBtu. The use of such price, as compared to the posted price of \$3.387 per MMBtu, 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.

Prices obtained for oil and gas production depend upon numerous factors that are beyond the control of the Trust. Inflationary pressures continued during 2025, which has impacted the cost of goods and services for operators on the Underlying Properties and administrative costs for the Trust.

As of May 2024, Blackbeard has provided the Trustee information necessary to calculate the net proceeds after the announcement date for monthly distributions. In accordance with the Trust indenture, if royalty income is received from the Waddell Ranch properties on or prior to the record date, it will be included in the following month's distribution, rather than the current month's distribution. There was no royalty income received for the year ending December 31, 2025.

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 oil and gas production increased approximately 56% and 46% respectively, from 2024 to 2025 which the Trustee believes were likely primarily due to new development based on the increased levels of capital expenditures.

Total capital expenditures for the twelve months of production reported in 2025 and used in the net overriding royalty calculation were approximately \$228.7 million (gross). Total capital expenditures were \$109.4 million (gross) in 2024 and \$120.4 million (gross) in 2023.

Development information for the Waddell Ranch properties, such as well activity, completions, workovers, remedial activities, and plugging and abandonment, is not provided by Blackbeard.

Blackbeard does not provide a proposed capital expenditure budget.

In 2025, lease operating expense and property taxes on the Waddell Ranch properties amounted to approximately \$98.0 million, compared to approximately \$82.2 million in 2024, and approximately \$79.6 million in 2023.

The Trustee was previously advised by the operator that as of December 31, 2023, the majority of Waddell Ranch oil production is now pipeline connected and sold under long term crude purchase agreements. Blackbeard would not confirm if this information remained accurate for 2024 or 2025.

During 2025, the monthly royalty receipts were invested by the Trustee in cash and cash equivalents until the monthly distribution date, and earned interest totaled \$72,761. Interest income for 2024 and 2023 was \$150,779 and \$85,879, respectively.

General and administrative expenses in 2025 were \$1,827,899 compared to \$1,698,776 in 2024 and \$1,118,096 in 2023, primarily due to audit of properties and other professional services. The reserve balance for administrative expenses for any potentially extraordinary events and/or expenses was \$1,100,000 as of December 31, 2025, 2024 and 2023. There were no additions to the reserves for expenses during the years ended December 31, 2025, 2024 and 2023.

Distributable income for 2025 was \$14,300,162 or \$0.31 per Unit. Distributable income includes a \$4.5 million partial settlement received from Blackbeard declared in the September 2025 distribution that was paid on October 15, 2025. The \$4.5 million partial payment is included in the financial statements under "Statements of Distributable Income" and "Statement of Changes in Trust Corpus" as of December 31, 2025, as well as in "Quarterly Schedule of Distributable Income (Unaudited) for the year ended December 31, 2025" (See Notes 3 and 7).

Distributable income for 2024 was \$25,415,368 or \$0.55 per Unit.

Distributable income for 2023 was \$27,978,487 or \$0.060 per Unit.

Results of the Fourth Quarters of 2025 and 2024

Royalty income received by the Trust for the fourth quarter of 2025 amounted to \$2,652,251 or \$0.06 per Unit, a decrease from the fourth quarter of 2024, when the Trust received royalty income of \$3,784,959 or \$0.08 per Unit. The decrease in the fourth quarter of 2025 was due in part to no royalty income being received from the Waddell Ranch properties for the full quarter ended December 31, 2025, as opposed to just the last two months of the quarter ended December 31, 2024. Interest income for the fourth quarter of 2025 amounted to \$25,437 compared to \$28,091 for the fourth quarter of 2024. The decrease in interest income is primarily attributable to decreased amounts of funds available for investment. Total general and administrative expenses were \$232,880 for the fourth quarter of 2025 compared to \$382,860 for the fourth quarter of 2024. The decrease in expenses primarily related to timing of payments of legal and auditor expenses.

Assets, liabilities, and distributions for each month in the fourth quarter of 2025 are as follows:

	October	November	December
Assets	\$ 2,195,609	\$ 2,158,851	\$ 1,877,733
Liabilities	\$ 2,033,186	\$ 1,996,428	\$ 1,715,167
Distributions declared	\$ 933,195	\$ 896,437	\$ 615,176
Distributions per Unit	\$ 0.020021	\$ 0.019233	\$ 0.013198

As of May 2024, Blackbeard, the operator of the Waddell Ranch properties, has provided the Trustee information necessary to calculate the net proceeds after the NYSE notification date such that royalty income of the Trust for the fourth quarter is associated with actual oil and gas production for the period from July through September of the current and prior years for the Waddell Ranch properties. Royalty income for the Trust for the fourth quarters of 2024 and 2025 for the Texas Royalty properties is associated with actual oil and gas production from August through October of both years. Oil and gas production attributable to the Underlying Properties for each month in the fourth quarter of 2025 and the comparable period for 2025 are as follows:

	Waddell Ranch Properties							
	2025				2024			
	September	October	November	Total	September	October	November	Total
Royalties								
Oil sales (Bbls)	298,802	326,081	328,684	953,567	174,367	198,955	189,143	562,465
Gas sales (Mcf)	1,432,575	1,429,268	1,425,154	4,286,997	1,077,265	1,181,264	1,101,120	3,359,649
Properties From Which The Royalties Were Carved:								
Oil:								
Total oil sales (Bbls)	398,402	434,775	438,245	1,271,422	232,489	265,273	252,191	749,953
Average per day (Bbls)	13,280	14,025	14,608	13,972	7,750	8,557	8,406	8,241
Average realized price per Bbl	\$ 66.22	\$ 63.15	\$ 68.98	\$ 64.16	\$ 77.35	\$ 75.00	\$ 68.98	\$ 73.78
Gas:								
Total gas sales (Mcf)	1,910,099	1,905,690	1,900,206	5,715,995	1,436,353	1,575,019	1,468,160	4,479,532
Average per day (Mcf)	63,670	61,474	63,340	62,813	47,878	50,807	48,939	49,226
Average realized price per Mcf	\$ 2.01	\$ 1.57	\$ 1.16	\$ 1.58	\$ 1.14	\$ 0.73	\$ 1.81	\$ 1.23

	Texas Royalty Properties							
	2025				2024			
	October	November	December	Total	October	November	December	Total
Royalties								
Oil sales (Bbls)	14,323	14,356	11,957	40,636	16,103	14,246	16,432	46,781
Gas sales (Mcf)	11,709	9,425	10,456	31,590	7,106	5,788	6,315	19,209
Properties From Which The Royalties Were Carved:								
Oil:								
Total oil sales (Bbls)	16,329	16,337	13,834	46,500	17,969	16,035	18,407	52,411
Average per day (Bbls)	527	545	446	505	580	535	594	570
Average realized price per Bbl	\$ 65.08	\$ 63.38	\$ 60.17	\$ 62.90	\$ 77.19	\$ 75.68	\$ 70.83	\$ 74.57
Gas:								
Total gas sales (Mcf)	13,282	10,723	12,089	36,094	7,932	6,521	7,073	21,526
Average per day (Mcf)	428	357	390	392	256	217	228	234
Average realized price per Mcf	\$ 8.10	\$ 7.10	\$ 8.32	\$ 7.88	\$ 10.02	\$ 11.30	\$ 11.05	\$ 10.79

For the Waddell Ranch properties, the posted price of oil decreased for the fourth quarter of 2025 compared to the fourth quarter of 2024, resulting in an average price per barrel of \$64.16 compared to \$73.78 in the same period of 2024. The average price of gas increased for the fourth quarter of 2025 compared to the same period in 2024, resulting in an average price per Mcf of \$1.58 compared to \$1.23 in the fourth quarter of 2024. Both oil and gas production increased in the fourth quarter of 2025 compared to the same period in 2024 for the Waddell Ranch properties.

For the Texas Royalty properties, the posted price of oil decreased for the fourth quarter of 2025 compared to the fourth quarter of 2024, resulting in an average price per barrel of \$62.90 compared to \$74.57 in the same period of 2024. The average price of gas decreased for the fourth quarter of 2025 compared to the same period in 2024, resulting in an average price per Mcf of \$7.88 compared to \$10.79 in the fourth quarter of 2024. Oil production decreased, while gas production increased in the fourth quarter of 2025 compared to the same period in 2024 for the Texas Royalty properties.

Development information for the Waddell Ranch properties such as well completions, workovers, remedial activities, and plugging and abandonment, is not provided by Blackbeard.

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 during the years ended December 31, 2025, 2024, or 2023.

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 modified cash basis of accounting and are not intended to present financial position and results of operations in conformity with accounting principles generally accepted in the United States of America ("GAAP"):

- 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 GAAP because revenues are not accrued in the month of production and certain cash reserves may be established for contingencies which could 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. Royalty Income

Revenues from royalty interests are recognized in the period in which amounts are received by the Trust. For the Texas Royalty Properties, 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. As of May 2024, Blackbeard has provided the Trustee information necessary to calculate the net proceeds for the Waddell Ranch properties after the NYSE notification date such that royalty income for 2025 is associated with actual oil and gas production for the 12-month period of October 1, 2024 through September 30, 2025. There was no royalty income received from Blackbeard for the calendar year 2025.

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

There are no new pronouncements that are expected to have a significant impact on the Trust's financial statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Trust's only long-term assets consist of royalty interests in producing oil and gas properties. As a result, the Trust is significantly exposed to fluctuations in the prices received for oil, natural gas and NGL produced and sold. 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.

Item 8. *Financial Statements and Supplementary Data*

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All financial statement schedules are omitted as they are inapplicable or the required information has been included in the financial statements or notes thereto.

Report of Independent Registered Public Accounting Firm

To the Unit Holders of
Permian Basin Royalty Trust and
Argent Trust Company, Trustee

Opinion on the Financial Statements

We have audited the accompanying statements of assets, liabilities and trust corpus of Permian Basin Royalty Trust (the Trust) as of December 31, 2025 and 2024, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2025, 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, 2025 and 2024, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2025, 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.

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. The Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the entity’s internal control over financial reporting. Accordingly, we express no such opinion.

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.

Basis of Accounting

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.

Critical Audit Matters

Critical audit matters are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. We determined that there are no critical audit matters.

/s/ WEAVER AND TIDWELL, L.L.P.

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

Houston, Texas
March 27, 2026

**PERMIAN BASIN ROYALTY TRUST
FINANCIAL STATEMENTS**

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

<u>ASSETS</u>	<u>December 31,</u>	
	<u>2025</u>	<u>2024</u>
Cash and Short-term Investments	\$ 1,715,167	\$ 2,122,585
Net Overriding Royalty Interests in Producing Oil and Gas Properties — Net (Notes 2 and 3)	162,566	164,407
Total	<u>\$ 1,877,733</u>	<u>\$ 2,286,992</u>
 <u>LIABILITIES AND TRUST CORPUS</u>		
Distribution Payable to Unit Holders	\$ 615,167	\$ 1,022,585
Commitments and Reserve for Contingencies (Note 8)	1,100,000	1,100,000
Total Liabilities	<u>\$ 1,715,167</u>	<u>\$ 2,122,585</u>
Trust Corpus — 46,608,796 Units of Beneficial Interest Authorized and Outstanding	162,566	164,407
Total	<u>\$ 1,877,733</u>	<u>\$ 2,286,992</u>

STATEMENTS OF DISTRIBUTABLE INCOME

	<u>For the year ended December 31,</u>		
	<u>2025</u>	<u>2024</u>	<u>2023</u>
Royalty Income	\$ 16,055,300	\$ 26,963,365	\$ 29,010,704
Interest Income	72,761	150,779	85,879
Total Income	<u>16,128,061</u>	<u>27,114,144</u>	<u>29,096,583</u>
General and Administrative Expenditures	1,827,899	1,698,776	1,118,096
Total Expenditures	<u>1,827,899</u>	<u>1,698,776</u>	<u>1,118,096</u>
Distributable Income	<u>\$ 14,300,162</u>	<u>\$ 25,415,368</u>	<u>\$ 27,978,487</u>
Distributable Income per Unit (46,608,796 Units)	<u>\$ 0.31</u>	<u>\$ 0.55</u>	<u>\$ 0.60</u>

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

STATEMENTS OF CHANGES IN TRUST CORPUS

	For the year ended December 31,		
	2025	2024	2023
Trust Corpus, Beginning of Year	\$ 164,407	\$ 221,474	\$ 279,433
Amortization of Net Overriding Royalty Interests	(1,841)	(57,067)	(57,959)
Distributable Income	14,300,162	25,415,368	27,978,487
Distributions Declared	(14,300,162)	(25,415,368)	(27,978,487)
Trust Corpus, End of Year	<u>\$ 162,566</u>	<u>\$ 164,407</u>	<u>\$ 221,474</u>

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

NOTES TO FINANCIAL STATEMENTS

1. Trust Organization and Provisions

The Permian Basin Royalty Trust (“Trust”) was established as of November 1, 1980. Argent Trust Company (“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, was the interest owner for the Waddell Ranch properties through November 1, 2019 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. In February 1997, BROG sold its interest in the Texas Royalty properties to Riverhill Energy. Riverhill Energy currently conducts the accounting operations for the Texas Royalty properties.

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.

BROG notified the Trust, that on November 1, 2019, the Waddell Ranch properties that are subject to the Net Overriding Royalty Conveyance (Permian Basin Royalty Trust - Waddell Ranch) dated November 1, 1980 (the “Waddell Ranch Conveyance”), were sold to Blackbeard Operating, LLC (“Blackbeard”) of Fort Worth, Texas. Blackbeard became the operator effective as of April 1, 2020.

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.

On November 4, 2021, Simmons Bank announced that it had entered into an agreement with Argent Trust Company, a Tennessee chartered trust company (“Argent”), pursuant to which Simmons Bank would be resigning as trustee of the Trust and would nominate Argent as successor trustee of the Trust. The effective date of Simmons Bank’s resignation and Argent’s appointment as successor trustee was December 30, 2022. The defined term “Trustee” as used herein shall refer to Bank of America N.A. for periods prior to August 29, 2014, shall refer to Southwest Bank for periods from August 29, 2014 through February 19, 2018, shall refer to Simmons Bank for periods from February 20, 2018 through December 29, 2022, and shall refer to Argent for periods on and after December 30, 2022.

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;
- 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 modified cash basis of accounting and are not intended to present financial position and results of operations in conformity with accounting principles generally accepted in the United States of America (“GAAP”):

- 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, are recorded 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 could 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 during the years ended December 31, 2025, 2024, or 2023.

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.

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

There are no new pronouncements that are expected to have a significant impact on the Trust’s financial statements.

3. Net Overriding Royalty Interests and Distribution to Unit Holders

The amount to be distributed to Unit holders (“Monthly Distribution Amount”) is determined monthly. 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.

Due to an NPI deficit, the Waddell Ranch properties did not contribute to royalty income from October 2024 through December 2025.

Distributable income includes a \$4.5 million partial settlement received from Blackbeard declared in the September 2025 distribution that was paid on October 15, 2025. The \$4.5 million partial payment is included in the financial statements under “Statements of Distributable Income” and “Statement of Changes in Trust Corpus” as of December 31, 2025, as well as in “Quarterly Schedule of Distributable Income (Unaudited) for the year ended December 31, 2025”.

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, 2025 and 2024 was \$10,812,650 and \$10,810,809, respectively.

4. Excess Costs

If monthly costs exceed revenues for the Waddell Ranch properties or Texas Royalty properties, such excess costs must be recovered, with accrued interest, from future net proceeds and cannot reduce net proceeds from the other conveyance. The Waddell Ranch properties did not contribute to royalty income for the months of October 2024 through December 2025, such that the Waddell Ranch properties were in a deficit position as of December 31, 2025.

The following table summarizes excess costs activity, cumulative excess costs balance, and accrued interest to be recovered as calculated by Blackbeard.

	Underlying Properties	Net to the Trust
Cumulative excess costs remaining at 12/31/2024	\$ 13,623,356	\$ 10,217,517
Net excess costs (recovery) for the quarter ended 3/31/25	\$ 13,918,276	\$ 10,438,707
Net excess costs (recovery) for the quarter ended 6/31/25	\$ 8,337,807	\$ 6,253,355
Net excess costs (recovery) for the quarter ended 9/30/25	\$ 7,669,844	\$ 5,752,383
Net excess costs (recovery) for the quarter ended 12/31/25	\$ 17,292,655	\$ 12,969,491
Cumulative excess costs remaining at 12/31/2025	\$ 60,841,938	\$ 45,631,453
Accrued interest at 12/31/25	\$ 3,025,675	\$ 2,269,256
Total remaining to be recovered at 12/31/25	\$ 63,867,613	\$ 47,900,709

For the year ended December 31, 2025, excess costs were \$60,841,938 (\$45,631,453 net to the Trust) for the Waddell Ranch properties. Accrued interest was \$3,025,675 (\$2,269,256 net to the Trust). As of December 31, 2024, excess costs were \$13,500,104 (\$10,125,078 net to the Trust) for the Waddell Ranch properties. Accrued interest, as of December 31, 2024, was \$123,252 (\$92,439 net to the Trust).

5. 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, for federal income tax purposes, 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. 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. Argent Trust Company, EIN: 62-1437218, 3838 Oak Lawn Ave, Suite 1720, 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 Internal Revenue Service ("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, her or its 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 2025, 2024, and 2023, 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 administration 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 attributable to the Royalties, limited to 100% of the net income from such Royalties. 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.

Unit holders must maintain records of their adjusted basis in their Trust Units (generally the Unit holder's 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 IRS could 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.

The classification of the Trust's income for purposes of the passive loss rules may be important to a Unit holder. Interest and royalty income attributable to ownership of Trust Units and any gain on the sale thereof are generally considered portfolio income and not income from a "passive activity," to the extent a Unit holder acquires and holds Trust Units as an investment and not in the ordinary course of a trade or business. Therefore, in general, interest and royalty income attributable to ownership of Trust Units may not be offset by losses from any passive activities. Unit holders should consult their tax advisor 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, 2023, and for the year ending December 31, 2024. However, 2024 was the last year that the Trust provided individual unitholder tax information worksheets. This decision was made after carefully considering the cost-benefit of providing those worksheets: taking into account the monthly cost of the third-party data gathering service, the cost to print the tax booklets and letters, and the cost to mail the tax booklets and letters. The same information can be derived using both the tax calculator and the cost depletion calculator on the Trust's website, along with the tax booklet that is also posted on the Trust's website. 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 WHFIT for federal income tax purposes.

Under the TCJA, for tax years beginning after December 31, 2017 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. The U.S. federal income tax rate applicable to corporations is 21%, and such rate applies to both ordinary income and capital gains.

Individuals may incur expenses in connection with the acquisition or ownership of Trust Units. For tax years beginning before January 1, 2018 and after December 31, 2025, 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 the TCJA, for tax years beginning after December 31, 2017 and before January 1, 2026, miscellaneous itemized deductions are not allowed.

On July 4, 2025, the OBBBA was signed into law. The OBBBA includes significant federal income tax provisions, such as the permanent extension of the income tax rates set by the TCJA, the continued suspension of miscellaneous itemized deductions and the restoration of favorable tax treatment for certain business provisions. The legislation has multiple effective dates, with certain provisions effective in 2025 and others implemented through 2027. Each Unit holder should consult their own tax advisor regarding the potential tax consequences of the OBBBA and its impact on such person's ownership of Trust Units.

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.

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 advisor regarding the possible implications of these withholding provisions on their investment in Trust Units.

On August 19, 2025, Argent, as Trustee of the Trust announced that it had reached the Settlement Agreement in connection with its litigation against Blackbeard, the operator of the properties in the Waddell Ranch, in Crane County, Texas, in which the Trust holds a 75% net overriding royalty. Pursuant to the lawsuit, the Trustee had sought to recover more than \$9 million in damages it alleged resulted from Blackbeard's failure to properly calculate and pay royalties due and owing the Trust. Pursuant to the Settlement Agreement, Blackbeard agreed to pay the Trust \$9,000,000, of which \$4,500,000 was paid in September 2025, with the remaining \$4,500,000 being paid to the Trust in equal amounts in each quarter in 2026. Pursuant to IRS regulations and court rulings, the Settlement Agreement proceeds have been included as gross income from the Waddell Ranch properties for percentage depletion purposes. Since cost depletion is calculated based on the amounts sold during the period divided by the estimated quantity of reserves and the Settlement Agreement originates from Blackbeard's failure to calculate the net royalty payable to the Trust (rather than the amounts sold), the Settlement Agreement proceeds are not included in the computation of cost depletion.

The foregoing summary is not exhaustive and does not purport to be complete. Many other provisions of the federal income tax laws may affect individual Unit holders. The federal income tax consequences to a Unit holder of the acquisition, ownership or disposition of Units will depend in part on the Unit holder's individual tax circumstances. Unit holders should consult their tax advisor regarding all Trust tax compliance matters.

6. Supplemental Oil and Gas Reserve Information (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)	BOE
December 31, 2022	11,553	25,737	15,843
Extensions, discoveries, and other additions	4,504	8,064	5,848
Revisions of previous estimates	(2,118)	7,137	(929)
Production	(2,277)	(12,175)	(4,306)
December 31, 2023	11,662	28,763	16,456
Extensions, discoveries, and other additions	2,213	6,195	3,245
Revisions of previous estimates	(3,293)	460	(3,216)
Production	(2,214)	(12,201)	(4,248)
December 31, 2024	8,368	23,217	12,237
Extensions, discoveries, and other additions	4,886	12,148	6,911
Revisions of previous estimates	3,563	17,881	6,543
Production	(3,433)	(15,541)	(6,023)
December 31, 2025	13,384	37,705	19,668

Revisions to proved reserve volumes in each year were primarily attributable to changes in commodity prices and variations in the performance of the underlying net profits interests relative to the prior year reserve report. The performance-related revisions reflect several factors, including the level of development activity, production volumes, and development costs associated with the net profits interests.

- For the year ended December 31, 2025, revisions increased proved reserves primarily as a result of improved performance of the net profits interests, associated with significant development activity at the Waddell Ranch, which increased reserve volumes by 7,582 thousand barrels of oil equivalent ("MBOE"). This favorable impact was partially offset by lower commodity prices, which reduced reserve volumes by 1,039 MBOE.
- For the year ended December 31, 2024, proved reserve quantities were revised downward primarily due to lower performance of the net profits interests, resulting in a decrease of 3,104 MBOE, together with the effect of lower commodity prices, which reduced reserve volumes by 112 MBOE.
- For the year ended December 31, 2023, revisions to proved reserve quantities were primarily attributable to lower commodity prices, which reduced reserve volumes by 4,904 MBOE. This decrease was partially offset by improved performance of the net profits interests, which increased reserve volumes by 3,975 MBOE.

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

Proved Developed Reserves:	Oil (Bbls)	Gas (Mcf)	BOE
December 31, 2022	8,022	21,216	11,558
December 31, 2023	7,236	21,001	10,736
December 31, 2024	8,368	23,217	12,237
December 31, 2025	13,384	37,705	19,668

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

Proved Undeveloped Reserves:	Oil (Bbls)	Gas (Mcf)	BOE
December 31, 2022	3,531	4,521	4,284
December 31, 2023	4,427	7,762	5,720
December 31, 2024	—	—	—
December 31, 2025	—	—	—

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 total proved oil and gas reserve quantities attributable to the Trust. Information presented is based upon valuation of proved reserves by using discounted cash flows based upon average oil and gas prices (\$65.34 per bbl and \$3.387 per MMBtu, 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 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,	2025	2024	2023
Future net cash inflows	\$ 925,721	\$ 643,652	\$ 897,415
Discount of future net cash flows @ 10%	(377,799)	(272,286)	(388,866)
Standardized measure of discounted future net cash inflows	<u>\$ 547,922</u>	<u>\$ 371,366</u>	<u>\$ 508,549</u>

The change in the standardized measure of discounted future net cash flows for the years ended December 31, 2025, 2024 and 2023 is as follows (in thousands):

	Total		
	2025	2024	2023
January 1	\$ 371,366	\$ 508,548	\$ 686,467
Extensions, discoveries, and other additions	220,395	108,923	185,611
Accretion of discount	37,136	50,855	68,646
Revisions of previous estimates and other	(69,420)	(269,997)	(403,164)
Royalty income	(11,555)	(26,963)	(29,011)
December 31	<u>\$ 547,922</u>	<u>\$ 371,366</u>	<u>\$ 508,549</u>

Subsequent to December 31, 2025, 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 March 16, 2026, NYMEX posted oil prices were approximately \$93.39 per barrel, which compared to the posted price of \$65.34 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. NYMEX posted gas prices were \$3.03 per MMBtu on March 16, 2026. The use of such price, as compared to the posted price of \$3.387 per MMBtu, 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.

7. Quarterly Schedule of Distributable Income (Unaudited)

The following is a summary of the unaudited quarterly schedule of royalty income, distributable income, and distributions declared (per unit) for the two years ended December 31, 2025:

<u>2025</u>	<u>Royalty Income</u>	<u>Distributable Income</u>	<u>Distributable Income and Distribution Per Unit</u>
First Quarter	\$ 3,054,697	\$ 2,596,212	\$ 0.055701
Second Quarter	3,089,889	2,397,255	0.051432
Third Quarter	7,258,463	6,861,887	0.147222
Fourth Quarter	2,652,251	2,444,808	0.052452
Total	<u>\$ 16,055,300</u>	<u>\$ 14,300,162</u>	<u>\$ 0.306807</u>

<u>2024</u>	<u>Royalty Income</u>	<u>Distributable Income</u>	<u>Distributable Income and Distribution Per Unit</u>
First Quarter	\$ 6,005,642	\$ 5,492,206	\$ 0.117831
Second Quarter	8,803,389	8,436,688	0.181009
Third Quarter	8,366,375	8,053,284	0.172782
Fourth Quarter	3,787,959	3,433,190	0.073658
Total	<u>\$ 26,963,365</u>	<u>\$ 25,415,368</u>	<u>\$ 0.545280</u>

8. State Tax Considerations

All revenues from the Trust are from sources within Texas, which does not impose an individual income tax. Therefore, no part of the income produced by the Trust is subject to an individual income tax in Texas. However, 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 advisor regarding the possible state tax implications of owning Trust Units.

9. 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.

10. General and Administrative Expenses

General and administrative expenses for the years ended December 31, 2025, 2024, and 2023 were as follows:

	<u>2025</u>	<u>2024</u>	<u>2023</u>
Trustee's fee	\$ 114,095	\$ 122,730	\$ 95,443
Professional fees	\$ 1,181,943	\$ 895,520	\$ 456,657
Unit holder service fees	\$ 528,494	\$ 553,340	\$ 526,155
Other	\$ 3,367	\$ 127,186	\$ 39,840
Total General and Administrative Expenses	<u>\$ 1,827,899</u>	<u>\$ 1,698,776</u>	<u>\$ 1,118,095</u>

11. Subsequent Events

Subsequent to December 31, 2025, the Trust declared the following distributions:

Monthly Record Date	Payment Date	Distribution per Unit
January 30, 2026	February 13, 2026	\$ 0.040056
February 27, 2026	March 13, 2026	\$ 0.014221
March 20, 2026	April 14, 2026	\$ 0.010662

Subsequent to December 31, 2025, the Trust received a quarterly settlement payment of \$1,125,000 on January 2, 2026 pursuant to its Settlement Agreement with Blackbeard. This payment was included in the January 2026 distribution to Unit holders.

* * * * *

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 Blackbeard Operating, LLC, the operator of the Waddell Ranch properties, and Riverhill Energy Corporation, the operator 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 twelve months ended December 31, 2025 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, 2025.

Item 9B. Other Information.

- (a) None.
- (b) The Trust does not have any directors or officers, and as a result, no such person adopted or terminated any Rule 10b5-1 trading arrangement or any non-Rule 10b5-1 trading arrangement, as defined in Item 408(a) of Regulation S-K, nor did the Trust adopt or terminate any Rule 10b5-1 trading arrangement during the most recent fiscal quarter.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspection.

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 2025, no person who was a beneficial owner of more than ten percent of the Trust's Units failed to file on a timely basis any report required by Section 16(a), with the exception of one late Form 3 and one late Form 4 filed by Eric L. Oliver, SoftVest Advisors, LLC, SoftVest, LP, and SoftVest GP I, LLC.

STANDARDS OF CONDUCT

Because the Trust has no employees, it does not have a code of ethics. Employees of the Trustee, Argent Trust Company, must comply with the company's code of ethics which may be found at www.argentfinancial.com.

INSIDER TRADING POLICY

Because the Trust does not have officers, directors, or employees, it has not adopted insider trading policies and procedures governing the purchase, sale and/or other disposition of Trust securities by such persons.

Item 11. *Executive Compensation*

During the years ended December 31, 2025, 2024 and 2023, the Trustee for such periods received total remuneration as follows:

<u>Name of Individual or Number of Persons in Group</u>	<u>Cash Compensation (1)</u>	<u>Year</u>
Argent Trust Company, Trustee	\$ 114,095	2025
Argent Trust Company, Trustee	\$ 122,730	2024
Argent Trust Company, Trustee	\$ 95,443	2023

- (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.

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, 2025:

<u>Name</u>	<u>Number of</u> <u>Units</u> <u>Owned(1)</u>	<u>Percent(2)</u>
Loyd Powell(3)	3,372,195	7.24%
Gideon Powell(3)	1,287,004	2.76%
SoftVest, LP(4)	6,217,107	13.3%
Horizon Kinetics Asset Management LLC(5)	5,839,825	12.5%

- (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, 2025.
- (3) Based on Schedule 13G/A filed February 11, 2021, reporting ownership as of December 31, 2020, jointly and as a group by Loyd Powell and Gideon Powell. The address for each of Loyd Powell and Gideon Powell is P.O. Box 12208; Suite 1610, Dallas, Texas 75225.
- (4) Based on Schedule 13D/A filed December 29, 2025, reporting ownership as of December 26, 2025, jointly by SoftVest Advisors, LLC, SoftVest, LP, SoftVest GP I, LLC, and Eric L. Oliver. The address for each of SoftVest Advisors, LLC, SoftVest, LP, SoftVest GP I, LLC, and Eric L. Oliver is 400 Pine Street, Suite 1010, Abilene, TX, 79601. Per the Schedule 13D/A, such ownership excludes 17,000 Units held by family members and partnerships for the benefit of Eric L. Oliver, of which he disclaims beneficial ownership.
- (5) Based on Schedule 13G/A filed July 2, 2025, reporting ownership as of June 3, 2025 by Horizon Kinetic Asset Management LLC. The address for Horizon Kinetic Asset Management LLC is 470 Park Avenue South, 8th Floor South, New York, NY 10016.

(b) *Security Ownership of Management.* The Trust has no directors or officers. Argent Trust Company, the Trustee, held as of March 23, 2026, no Units in any fiduciary capacity.

(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, 2025, 2024 and 2023.

Item 14. Principal Accounting Fees and Services

Fees for services performed by Weaver and Tidwell, L.L.P. for the years ended December 31, 2025 and 2024 are:

<u>Weaver and Tidwell, L.L.P.</u>	<u>2025</u>	<u>2024</u>
Audit fees	\$ 163,013	\$ 115,100
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	<u>\$ 163,013</u>	<u>\$ 115,100</u>

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.

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>Report of Independent Registered Public Accounting Firm (PCAOB ID Number 410)</u>	33
<u>Statements of Assets, Liabilities and Trust Corpus at December 31, 2025 and 2024</u>	34
<u>Statements of Distributable Income for Each of the Three Years in the Period Ended December 31, 2025</u>	34
<u>Statements of Changes in Trust Corpus for Each of the Three Years in the Period Ended December 31, 2025</u>	35
<u>Notes to Financial Statements</u>	36

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

<u>Exhibit Number</u>	<u>Exhibit</u>
(4)(a)	— <u>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.*</u>
(b)	— <u>Amendment No. 1 to the Amended and Restated Royalty Trust Indenture of Permian Basin Royalty Trust, dated May 4, 2022, heretofore filed as Exhibit 4.1 to the Trust's Current Report on Form 8-K to the Securities and Exchange Commission filed on May 6, 2022 is incorporated herein by reference.*</u>
(c)	— 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)
(d)	— 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)
(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>
(97)	— <u>Executive Officer Compensation Recovery Policy**</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, Argent Trust Company, 3838 Oak Lawn Ave, Suite 1720, Dallas, Texas 75219.

** Filed herewith.

(P) Paper exhibits.

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.

ARGENT TRUST COMPANY,
TRUSTEE FOR THE
PERMIAN BASIN ROYALTY TRUST

By: /s/Nancy Willis
Nancy Willis
Director of Royalty Trust Services

Date: July 14, 2026

(The Trust has no directors or executive officers.)

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

6500 RIVER PLACE BLVD, SUITE 3-200
AUSTIN, TEXAS 78730-1111
512-249-7000

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817-336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 1900
HOUSTON, TEXAS 77002-5008
713-651-9944

CONSENT OF CAWLEY, GILLESPIE & ASSOCIATES, INC.

July 14, 2026

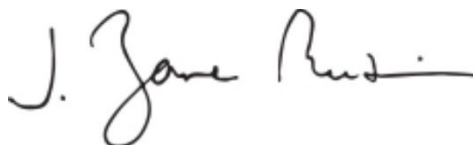
Permian Basin Royalty Trust
Argent Trust Company
3838 Oak Lawn Avenue, Suite 1720
Dallas, Texas 75219

Ladies and Gentlemen:

Cawley, Gillespie & Associates, Inc., hereby consents to the use of the oil and gas reserve information in the Permian Basin Royalty Trust Securities and Exchange Commission Form 10-K/A for the year ending December 31, 2025 and in the Permian Basin Royalty Trust Annual Report for the year ending December 31, 2025, based on reserve reports dated February 26, 2026, prepared by Cawley, Gillespie & Associates, Inc.

Submitted,

Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693

A handwritten signature in black ink, appearing to read "J. Zane Meekins". The signature is fluid and cursive, with a long horizontal stroke at the end.

J. Zane Meekins, P. E
Executive Vice President

Certification Required by Rule 13a-14(a) or Rule 15d-14(a)

I, Nancy Willis, certify that:

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

In giving the certifications in paragraphs 4 and 5 above, I have relied to the extent I consider reasonable on information provided to me by Blackbeard Operating, LLC and Riverhill Energy Corporation.

Date: July 14, 2026

By: /s/ Nancy Willis
Nancy Willis
Director of Royalty Trust Services
Argent Trust Company

Certification required by Rule 13a-14(b) or Rule 15d-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Amendment No. 1 to Annual Report of Permian Basin Royalty Trust (the “Trust”) on Form 10-K/A for the annual period ended December 31, 2025 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), the undersigned, not in its individual capacity but solely as the trustee of the Trust, certifies pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to its knowledge:

- (1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Trust.

ARGENT TRUST COMPANY,
TRUSTEE FOR THE
PERMIAN BASIN ROYALTY TRUST

Date: July 14, 2026

By: /s/Nancy Willis
Nancy Willis
Director of Royalty Trust Services

A signed original of this written statement required by Section 906 has been provided to the Permian Basin Royalty Trust and will be retained by the Permian Basin Royalty Trust and furnished to the Securities and Exchange Commission or its staff upon request.

Permian Basin Royalty Trust
Executive Officer Compensation Recovery Policy
(As adopted November 22, 2023)

This Executive Officer Compensation Recovery Policy (this “**Policy**”) of Permian Basin Royalty Trust (the “**Trust**”) is hereby adopted as of November 22, 2023 (the “Effective Date”) by Argent Trust Company (the “**Trustee**”) in compliance with Section 10D of the Securities Exchange Act of 1934 and Section 303A.14 of the New York Stock Exchange (the “**NYSE**”) Listed Company Manual (“**Section 303A.14**”). Certain terms shall have the meanings set forth in “Section 3. Definitions” below.

Section 1. Recovery Requirement

Subject to Section 4 of this Policy, in the event the Trust is required to prepare an Accounting Restatement, then the Trustee hereby directs the Trust, to the fullest extent permitted by governing law, to recover from each Executive Officer the amount received by an Executive Officer, if any, of Erroneously Awarded Compensation, with such recovery occurring reasonably promptly after the Restatement Date relating to such Accounting Restatement. An Executive Officer shall be deemed to have “received” Incentive-Based Compensation in the Trust’s fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of the Incentive-Based Compensation occurs after the end of that fiscal period.

The Trustee may effect recovery in any manner consistent with applicable law including, but not limited to, (a) seeking reimbursement of all or part of any Erroneously Awarded Compensation previously received by an Executive Officer and to the extent that the Executive Officer does not reimburse such Erroneously Awarded Compensation, suing and enforcing recovery against the Executive Officer for repayment of the Erroneously Awarded Compensation, together with any expenses (including, without limitation, legal fees) incurred by the Trust in enforcing such recovery, (b) cancelling prior grants of Incentive-Based Compensation, whether vested or unvested, restricted or deferred, or paid or unpaid, and through the forfeiture of previously vested equity awards, (c) cancelling or setting-off against planned future grants of Incentive-Based Compensation, (d) deducting all or any portion of such Erroneously Awarded Compensation from any other remuneration payable by the Trust to such Executive Officer, and (e) any other method authorized by applicable law or contract.

The Trust’s right to recovery pursuant to this Policy is not dependent on if or when the Accounting Restatement is filed with the Securities and Exchange Commission.

Section 2. Incentive-Based Compensation Subject to this Policy.

This Policy applies to all Incentive-Based Compensation received by each Executive Officer on or after the Effective Date:

- (i) if such Incentive-Based Compensation was received on or after the date such person became an Executive Officer of the Trust;
- (ii) if such Executive Officer served as an Executive Officer at any time during the performance period for that Incentive-Based Compensation; and
- (iii) if such Incentive-Based Compensation was received during the three completed fiscal years immediately preceding the Restatement Date (including any transition period that results from a change in the Trust’s fiscal year that is within or immediately following those three completed fiscal years; provided that a transition period of nine to 12 months is deemed to be a completed fiscal year).

This Policy shall apply and govern Incentive-Based Compensation received by any Executive Officer, notwithstanding any contrary or supplemental term or condition in any document, plan or agreement including without limitation any employment contract, indemnification agreement, equity agreement, or equity plan document.

Section 3. Definitions:

For purposes of this Policy, the following terms have the meanings set forth below:

- **“Accounting Restatement”** means an accounting restatement due to the material noncompliance of the Trust with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error (i) in previously issued financial statements that is material to the previously issued financial statements (commonly referred to as a “Big R” restatement) or (ii) that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (commonly referred to as a “little r” restatement).
- **“Erroneously Awarded Compensation”** means the amount of Incentive-Based Compensation received that exceeds the amount of Incentive-Based Compensation that otherwise would have been received by the Executive Officer had it been determined based on the restated amounts in the Accounting Restatement (computed without regard to any taxes paid). For Incentive-Based Compensation based on the price of units of beneficial interest in the Trust or total unitholder return (“TUR”), where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in the Accounting Restatement the Trust shall: (i) base the calculation of the amount on a reasonable estimate of the effect of the Accounting Restatement on the price of units of beneficial interest in the Trust or TUR upon which the Incentive-Based Compensation received was based; and (ii) retain documentation of the determination of that reasonable estimate and provide such documentation to the NYSE or, if a class of securities of the Trust is no longer listed on the NYSE, such other national securities exchange or national securities association on which a class of the Trust’s securities is then listed for trading.
- **“Executive Officer”** has the meaning set forth in Section 303A.14(e) of the NYSE Listed Company Manual. For purposes of clarity, “Executive Officer” includes officers or employees of the Trustee who perform policy-making functions for the Trust.
- **“Financial Reporting Measure”** is (i) any measure that is determined and presented in accordance with the accounting principles used in preparing the Trust’s financial statements, or any measure derived wholly or in part from such measure, (ii) unit price and (iii) TUR. A Financial Reporting Measure need not be presented within the Trust’s financial statements or included in a filing with the Securities Exchange Commission.
- **“Incentive-Based Compensation”** means any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure (including, without limitation, unit price or TUR), including, any short-term or long-term incentive awards, cash bonuses, restricted unit awards that vest based on achievement of a Financial Reporting Measure. Equity awards that vest exclusively upon completion of a specified employment period, without any performance condition, and bonus awards that are discretionary or based on subjective goals or goals unrelated to Financial Reporting Measures, do not constitute Incentive-Based Compensation.
- **“NYSE”** means the New York Stock Exchange.
- **“Restatement Date”** means the earlier to occur of (i) the date the Trustee (or an officer or officers of the Trust or Trustee authorized to take such action if action by the board of directors of the Trust or Trustee is not required) concludes, or reasonably should have concluded, that the Trust is required to prepare an Accounting Restatement and (ii) the date a court, regulator, or other legally authorized body directs the Trust to prepare an Accounting Restatement.

Section 4. Exceptions to Recovery

Notwithstanding the foregoing, the Trust is not required to recover Erroneously Awarded Compensation to the extent that the Trustee has made a determination that recovery would be impracticable and that:

- (i) the direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered (provided, that, before concluding that it would be impracticable to recover based on the expense of enforcement, the Trust must make a reasonable attempt to recover such Erroneously Awarded Compensation and must document such attempts and provide such documentation to the NYSE);
- (ii) recovery would violate one or more laws of the home country that were adopted prior to November 28, 2022 (provided, that, before concluding that it would be impracticable to recover based on violation of home country law, the Trust must obtain an opinion of home country counsel, acceptable to the NYSE, that recovery would result in such a violation and provide a copy of such opinion to the NYSE);

- (iii) recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Trust and its subsidiaries, to fail to meet the requirements of 26 U.S.C. 401(a)(13) or 26 U.S.C. 411(a) and regulations thereunder; or
- (iv) any other exception permitted under Section 303A.14 of the NYSE Listed Company Manual.

Section 5. No Right to Indemnification or Insurance

The Trust shall not indemnify any Executive Officer against the loss of Erroneously Awarded Compensation or losses arising from any claims relating to the Trust's enforcement of this Policy. In addition, the Trust shall not pay, or reimburse any Executive Officer for, any premiums for a third-party insurance policy purchased by the Executive Officer or any other party that would fund any of the Executive Officer's potential recovery obligations under this Policy.

Section 6. Award Agreements and Plan Documents

The Trustee further directs the Trust to include clawback language in each of the Trust's incentive compensation plans such that each individual who receives Incentive-Based Compensation under those plans understands and agrees that all or any portion of such Incentive-Based Compensation may be subject to recovery by the Trust, and such individual may be required to repay all or any portion of such Incentive-Based Compensation, if (i) recovery of such Incentive-Based Compensation is required by this Policy, (ii) such Incentive-Based Compensation is determined to be based on materially inaccurate financial and/or performance information (which includes, but is not limited to, statements of earnings, revenues or gains); or (iii) repayment of such Incentive-Based Compensation is required by applicable federal or state securities and/or banking laws.

Section 7. Interpretation and Amendment of this Policy

The Trustee, in its discretion, shall have the sole authority to interpret and make any determinations regarding this Policy. Any interpretation, determination, or other action made or taken by the Trustee shall be final, binding, and conclusive on all interested parties. The determination of the Trustee need not be uniform with respect to one or more officers. The Trustee may amend this Policy from time to time in its discretion and shall amend the Policy to comply with applicable law or with any rules or standards adopted by the NYSE or any national securities exchange on which the Trust's securities are then listed. The Trustee may terminate this Policy at any time.

Any employees of the Trustee who assist in the administration of this Policy shall not be personally liable for any action, determination or interpretation made with respect to this Policy and shall be fully indemnified by the Trust to the fullest extent under applicable law and Trust policy with respect to any such action, determination or interpretation. The foregoing sentence shall not limit any other rights to indemnification of the employees of the Trustee under applicable law or Trust policy.

Section 8. Other Recoupment Rights.

The Trust intends that this Policy will be applied to the fullest extent of the law. Any right of recoupment under this Policy is in addition to, and not in lieu of, any other remedies or rights of recoupment that may be available to the Trust pursuant to the terms of any similar policy in any employment agreement, equity award agreement, or similar agreement and any other remedies available to the Trust under applicable law. Without by implication limiting the foregoing, following a restatement of the Trust's financial statements, the Trust also shall be entitled to recover any compensation received by the Chief Executive Officer and Chief Financial Officer that is required to be recovered by Section 304 of the Sarbanes-Oxley Act of 2002.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

6500 RIVER PLACE BLVD, SUITE 3-200
AUSTIN, TEXAS 78730-1111
512-249-7000

306 WEST SEVENTH STREET, SUITE 302
FORT WORTH, TEXAS 76102-4987
817-336-2461
www.cgaus.com

1000 LOUISIANA STREET, SUITE 1900
HOUSTON, TEXAS 77002-5008
713-651-9944

February 26, 2026

Ms. Nancy Willis
Permian Basin Royalty Trust
3838 Oak Lawn Avenue, Suite 1720
Dallas, Texas 75219

Re: Evaluation Summary
Permian Basin Royalty Trust Interests
Proved Reserves
As of December 31, 2025

*Pursuant to the Rules and Regulations of the
Securities and Exchange Commission for
Reporting Corporate Reserves and
Future Net Revenue*

Dear Ms. Willis:

As requested, we are submitting this report of the estimates of proved reserves and economics forecasts attributable to the Permian Basin Royalty Trust interests effective as of December 31, 2025, completed February 26, 2026 for the purpose of reporting corporate reserves and future net revenue. This report has been prepared for the Permian Basin Royalty Trust pursuant to the rules, regulations and guidelines of the Securities and Exchange Commission, Item 1202 (a) (8) of Regulation S-K, for reporting corporate reserves and future net revenue. We reviewed 100 percent of the total proved reserves of the Permian Basin Royalty Trust in connection with the preparation of this report. The proved reserves presented in this report constitute 100 percent of the proved reserves owned by the Permian Basin Royalty Trust, all of which are located in the United States.

Composite reserve estimates and economic forecasts for the proved reserves are summarized below:

			<i>Texas Royalty Properties</i>	<i>Waddell Ranch Properties</i>
			Proved Developed Producing	Proved Developed Producing
			Total Proved	
Net Reserves				
Oil/Condensate	- Mbbl	13,384.1	2,451.2	10,932.8
Gas	- MMcf	37,704.6	1,350.5	36,354.1
Net Revenue				
Oil/Condensate	- M\$	858,945.5	157,713.1	701,232.4
Gas	- M\$	106,738.5	8,233.3	98,505.2

Severance Taxes	- M\$	39,962.7	6,720.8	33,241.8
Operating Income (BFIT)	- M\$	925,721.3	159,225.7	766,495.6
Discounted at 10%	- M\$	547,922.2	66,206.0	481,716.2

In accordance with the Securities and Exchange Commission guidelines, the future net cash flow, operating income (BFIT), has been discounted at an annual rate of 10% to determine its “present worth”. The discounted value, “present worth”, is indicative of the time value of money. The discounted value, “present worth”, shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

The Permian Basin Royalty Trust consists of the Waddell Ranch Properties located in Crane County, Texas, and the Texas Royalty Properties located in various counties in Texas.

As to the assumptions, methods and procedures used in connection with the preparation of this report, prices were forecast in accordance with Securities and Exchange Commission rules and guidelines. The prices are determined as an unweighted arithmetic average of the first-day-of-the-month benchmark price for each month of 2025. The 12-month average benchmark Henry Hub spot gas price of \$3.387 per MMBtu and 12-month average benchmark WTI Cushing spot oil price of \$65.34 per barrel were used. The oil and gas prices were held constant throughout the life of the properties. The prices were adjusted for gravity, quality, heating value, transportation and marketing. For the Texas Royalty Properties, the gas prices were adjusted using a factor of 1.80, and the oil prices were adjusted using a differential of -\$1.00 per barrel. For the Waddell Ranch Properties, the gas prices were adjusted using a factor of 0.80, and the oil prices were adjusted using a differential of -\$1.20 per barrel. Deductions were applied to the net gas volumes for fuel and shrinkage. For the Texas Royalty Properties, the adjusted volume-weighted average product prices over the life of the properties are \$64.34 per barrel and \$6.10 per MCF, respectively. For the Waddell Ranch Properties, the adjusted volume-weighted average product prices over the life of the properties are \$64.14 per barrel and \$2.71 per MCF, respectively.

For the Waddell Ranch Properties, operating expenses were based on an analysis of data provided by Blackbeard Operating. Operating expenses include direct lease operating expenses and administrative overhead and were forecast as \$5,000 per well per month and \$13.00 per barrel of oil. No operating expense data is available for the Texas Royalty Properties since they are royalty interests only. Based on an analysis of the Permian Basin Royalty Trust Monthly reports, severance taxes were forecast as 4.05% of oil and gas revenue for the Texas Royalty Properties. For the Waddell Ranch Properties, severance taxes were forecast as 4.6% and 1.0% of oil and gas revenue, respectively. The ad valorem taxes were forecast as 1.3% and 5.45% of total revenue for the Waddell Ranch Properties and the Texas Royalty Properties, respectively. Neither expenses nor investments were escalated. The cost of plugging and the salvage value of equipment have been considered.

The reserves were estimated using the production performance, volumetric or analogy methods, or a combination of these methods. In each case, we used the method or combination of methods that we considered appropriate and necessary to establish the reserves and conclusions presented. Riverhill Energy Corporation supplied the royalty production data for the Texas Royalty Properties. For these properties, the proved producing reserves are forecast using the production performance, decline analysis method to an estimated final production rate equal to approximately one-tenth of the current production rate. The producing reserves for the Waddell Ranch Properties were estimated using the production performance or analogy methods or a combination of these methods. The non-producing and undeveloped reserves were estimated using the analogy or volumetric methods or a combination of these methods.

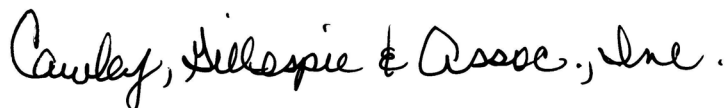
The reserve classifications conform to the definitions and criteria of the Securities and Exchange Commission. The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. The possible effects of

changes in legislation or other Federal or State restrictive actions which could affect the reserves and economics have not been considered. We are not aware of any legislative changes or restrictive actions that may possibly impact the reserves or economics as presented. Possible environmental liability related to the properties has not been investigated nor considered. The assumptions, data, methods and procedures as described are appropriate for the purpose of this report. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. Due to the inherent uncertainties of reserves estimates, future production rates, commodity prices, costs and expenses, it should be realized that the reserves actually recovered, the revenue received and the actual cost incurred could be more or less than the estimated amounts.

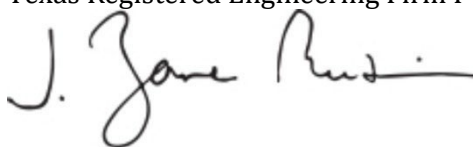
The reserve estimates were based on interpretations of factual data furnished by Blackbeard Operating, Riverhill Energy Corporation and the Permian Basin Royalty Trust. Liquid and gas price information, cost and expense history, subject wells and ownership were supplied by one or more of the above and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc. We have used all methods and procedures that we consider necessary under the circumstances to prepare this report.

Cawley, Gillespie & Associates, Inc. is independent with respect to the Permian Basin Royalty Trust as provided in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information promulgated by the Society of Petroleum Engineers. Neither Cawley, Gillespie & Associates, Inc. nor any of its employees has any interest in the subject properties. Neither the employment to make this study nor the compensation is contingent on the results of our work or the future performance of the subject properties. Cawley, Gillespie and Associates, Inc. is a Texas registered engineering firm, F-693, of professional engineers and geologists serving the oil and gas industry for over fifty years. This report was prepared by, or under the supervision of, J. Zane Meekins, a Texas registered professional engineer (License No. 71055).

Respectfully submitted,

A handwritten signature in black ink that reads "Cawley, Gillespie & Assoc., Inc." in a cursive script.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

A handwritten signature in black ink that reads "J. Zane Meekins" in a cursive script.

J. Zane Meekins, P.E.
Executive Vice President