PERMIAN BASIN ROYALTY TRUST
Form 10-K
March 02, 2012
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2011

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	**75-6280532**
(State or Other Jurisdiction of Incorporation or Organization)	*(I.R.S. Employer Identification No.)*

U.S. Trust, Bank of America

Private Wealth Management

Trust Department

P.O. Box 830650

Dallas, Texas 75202

(Address of Principal Executive Offices; Zip Code)

(Registrant s Telephone Number, Including Area Code)

(214) 209-2400

Securities Registered pursuant to section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Units of Beneficial Interest	New York Stock Exchange

Securities Registered pursuant to section 12(g) of the Act:

None

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

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 þ No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

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

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

Large accelerated filer þ	Accelerated filer ¨	Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller Reporting Company ¨

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

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 $1,008,614,345.44.

At March 2, 2012, there were 46,608,796 Units of Beneficial Interest of the Trust outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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FORWARD LOOKING INFORMATION

Certain information included in this report contains, and other materials filed or to be filed by the Trust with the Securities and Exchange Commission (as well as information included in oral statements or other written statements made or to be made by the Trust) may contain or include, forward looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. Such forward looking statements may be or may concern, among other things, capital expenditures, drilling activity, development activities, production efforts and volumes, hydrocarbon prices and the results thereof, and regulatory matters. Although the Trustee believes that the expectations reflected in such forward looking statements are reasonable, such expectations are subject to numerous risks and uncertainties and the Trustee can give no assurance that they will prove correct. There are many factors, none of which is 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, anticipate, goal, should, assume, believe, or other words that 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. Bank of America Private Wealth Management, a banking association organized under the laws of the United States, as the successor of The First National Bank of Fort Worth, is now the Trustee of the Trust. In 2007, the Bank of America private wealth management group officially became known as U.S. Trust, Bank of America Private Wealth Management. The legal entity that serves as Trustee of the Trust did not change, and references in this Form 10-K to U.S. Trust, Bank of America Private Wealth Management shall describe the legal entity Bank of America, N.A. The principal office of the Trust (sometimes referred to herein as the Registrant) is located at 901 Main Street, Dallas, Texas (telephone number (214) 209-2400).

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

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

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

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 on page 8) that are subject to the Net Overriding Royalty Conveyance dated November 1, 1980 (the Texas Royalty Conveyance), were sold to Riverhill Energy Corporation (Riverhill Energy) of Midland, Texas. Effective March 31, 2006, ConocoPhillips acquired BRI pursuant to a merger between BRI and a wholly-owned subsidiary of ConocoPhillips. As a result of this acquisition, BRI and BROG are both wholly-owned subsidiaries of ConocoPhillips.

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

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

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

Cash held by the Trustee as a reserve for liabilities or contingencies (which reserves may be established by the Trustee in its discretion) or pending distribution is placed, at the Trustee s discretion, in obligations issued by (or unconditionally guaranteed by) the United States or any agency thereof, repurchase agreements secured by obligations issued by the United States or any agency thereof, or certificates of deposit of banks having a capital surplus and undivided profits in excess of $50,000,000, subject, in each case, to certain other qualifying conditions.

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

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

Website/SEC Filings

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

Widely Held Fixed Investment Trust Reporting Information

Some Trust Units are held by middlemen, as such term is broadly defined in U.S. Treasury Regulations (and includes custodians, nominees, certain joint owners, and brokers holding an interest for a customer in street name, collectively referred to herein as middlemen). Therefore, the Trustee considers the Trust to be a non-mortgage widely held fixed investment trust (WHFIT) for U.S. federal income tax purposes. U.S. Trust, Bank of America Private Wealth Management, EIN: 56-0906609, 901 Main Street, 17th Floor, Dallas, Texas 75202, telephone number (214) 209-2400, 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-permianbasintrust.com. Notwithstanding the foregoing, the middlemen holding Trust Units on behalf of Unit holders, and not the Trustee of the Trust, are solely responsible for complying with the information reporting requirements under the U.S. Treasury Regulations with respect to such Trust Units, including the issuance of IRS Forms 1099 and certain written tax statements. Unit holders whose Trust Units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the Trust Units.

Item 1A. *Risk Factors*

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

The Trust s monthly distributions are highly dependent upon the prices realized from the sale of crude oil and natural gas and a material decrease in such prices could reduce the amount of cash distributions paid to Unit holders. Crude oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust. Factors that contribute to price fluctuation include, among others:

- political conditions in major oil producing regions, especially in the Middle East;
- worldwide economic conditions;
- weather conditions;
- the supply and price of domestic and foreign crude oil or natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries to agree upon and maintain oil prices and production levels;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures; and
- the nature and extent of governmental regulation and taxation.

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

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 2012 net proceeds could increase compared to the electrical costs incurred during 2011 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 2012 net proceeds below the level that would exist if such costs remained at the level experienced in 2011. 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.

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

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

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

- historical production from the area compared with production rates from similar producing areas;
- the effects of governmental regulation;
- assumptions about future commodity prices, production and development costs, taxes, and capital expenditures;
- the availability of enhanced recovery techniques; and
- relationships with landowners, working interest partners, pipeline companies and others.

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

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

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

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

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

The Trust does not lend money and has limited ability to borrow money, which the Trustee believes limits the Trust s risk from the current tightening of 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

Any operator developing any of the Underlying Properties may at any time transfer all or part of its interest in the Underlying Properties to another party. Neither the Trust nor the Unit holders are entitled to vote on any transfer of the properties underlying the Royalties, and the Trust will not receive any proceeds of any such transfer. Following any transfer, the transferred property will continue to be subject to the Royalties, but the net proceeds from the transferred property will be calculated separately and paid by the transferee. The transferee will be responsible for all of the transferor s obligations relating to calculating, reporting and paying to the Trust the Royalties from the transferred property, and the transferor will have no continuing obligation to the Trust for that property.

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

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

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

The Trustee must sell the Royalties if the holders of 75% or more of the Units approve the sale or vote to terminate the Trust. The Trustee must also sell the Royalties if they fail to generate net revenue for the Trust of at least $1,000,000 per year over any consecutive two-year period. Sale of all of the Royalties will terminate the Trust. The net proceeds of any sale will be distributed to the Unit holders. The sale of the remaining Royalties and the termination of the Trust will be taxable events to the Unit holders. Generally, a Unit holder will realize gain or loss equal to the difference between the amount realized on the sale and termination of the Trust and his adjusted basis in such Units. Gain or loss realized by a Unit holder who is not a dealer with respect to such Units and who has a holding period for the Units of more than one year will be treated as long-term capital gain or loss except to the extent of any depletion recapture amount, which must be treated as ordinary income. Other federal and state tax issues concerning the Trust are discussed under Note 5 and Note 9 to the Trust s financial statements, which are included herein. Each Unit holder should consult his own tax advisor regarding Trust tax compliance matters, including federal and state tax implications concerning the sale of the Royalties and the termination of the Trust.

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

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

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

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

The financial statements of the Trust are prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States, or GAAP. Although this basis of accounting is permitted for royalty trusts by the U.S. Securities and Exchange Commission, the financial statements of the Trust differ from GAAP financial statements because revenues are not accrued in the month of production and cash reserves may be established for specified contingencies and deducted which could not be accrued in GAAP financial statements.

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.

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

The Trust has not received any written comments from the Securities and Exchange Commission staff regarding its periodic or current reports under the Act not less than 180 days before December 31, 2011, which comments remain unresolved.

Item 2. ***Properties***

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

A production index for oil and gas properties is the number of years derived by dividing remaining reserves by current production. The production index for the Trust properties based on the reserve report prepared by independent petroleum engineers as of December 31, 2011, is approximately 9.8 years.

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

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PRODUCING ACREAGE, WELLS AND DRILLING

Waddell Ranch Properties. The net profits/overriding royalty interest in the Waddell Ranch properties is the largest asset of the Trust. The mineral interests in the Waddell Ranch, from which such net royalty interests are carved, vary from 37.5% (Trust net interest) to 50% (Trust net interest) in 78,715 gross (34,205 net) producing acres. A majority of the proved reserves are attributable to six fields: Dune, Sand Hills (Judkins), Sand Hills (McKnight), Sand Hills (Tubb), University-Waddell (Devonian) and Waddell. At December 31, 2011, the Waddell Ranch properties contained 755 gross (340 net) productive oil wells, 188 gross (88 net) productive gas wells and 254 gross (109 net) injection wells.

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

Six major fields on the Waddell Ranch properties account for more than 80% of the total production. In the six fields, there are 12 producing zones ranging in depth from 2,800 to 10,600 feet.

Most prolific of these zones are the Grayburg and San Andres, which produce from depths between 2,800 and 3,400 feet. Also productive from the San Andres are the Sand Hills (Judkins) gas field and the Sand Hills (McKnight) oil field, the Dune (Grayburg/San Andres) oil field, and the Waddell (Grayburg/San Andres) oil field.

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

The Waddell Ranch properties are mature producing properties, and all of the major oil fields are currently being waterflooded for the purpose of facilitating enhanced recovery. Proved reserves and estimated future net revenues attributable to the properties are included in the reserve reports summarized below. BROG does not own the full working interest in any of the tracts constituting the Waddell Ranch properties and, therefore, implementation of any development programs will require approvals of other working interest holders as well as BROG. In addition, implementation of any development programs will be dependent upon oil and gas prices currently being received and anticipated to be received in the future. There were 4 gross (2 net) 2010 drill wells completed on the Waddell Ranch properties during 2011. At December 31, 2011, there were no drill wells and 13 workovers in progress on the Waddell Ranch properties. There was 1 gross (0.5 net) well drilled and completed on the Waddell Ranch properties during 2010. At December 31, 2010 there were 4 drill wells and 5 workovers in progress on the Waddell Ranch properties. There were 11 gross (5 net) wells drilled and completed on the Waddell Ranch properties during 2009. At December 31, 2009 there were no drill wells and 2 workovers in progress on the Waddell Ranch properties.

In 2011, there were no net productive and no dry exploratory wells drilled, and 2 net productive and no dry development wells drilled on the Waddell Ranch properties, compared to no net productive and no dry exploratory wells and 0.5 net productive and no dry development wells drilled in 2010. In 2009, there were no net productive and no dry exploratory wells drilled, and 5 net productive and no dry development wells drilled on the Waddell Ranch Properties.

BROG has advised the Trustee that the total amount of capital expenditures for 2011 with regard to the Waddell Ranch properties totaled $26.1 million. Capital expenditures include the cost of remedial and maintenance activities. This amount spent is approximately $3.1 million more than the budgeted amount projected by BROG for 2011. BROG has advised the Trustee that the capital expenditures budget for 2012 totals approximately $75.40 million, of which approximately $22.74 million (gross) is attributable to the 2012 drilling program, and $43.25 million (gross) to workovers and recompletions. The remaining $9.41 million is attributable to facilities. Accordingly, there is a 189% increase in capital expenditures for 2012 as compared with the 2011 capital expenditures. The major reason for the variance is the increase in the number of planned capital recompletions, addition of a drilling program, addition of waterflood expansion and an increased level of facility work. There will be 9 (7 producers, 2 injectors) new drill wells in 2012 as compared to no new drill wells in 2011.

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,

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Howard-Glasscock, Seminole and others located in 33 counties across Texas. The Texas Royalty properties consist of approximately 125 separate royalty interests containing approximately 303,000 gross (approximately 51,000 net) producing acres. Approximately 41% of the future net revenues discounted at 10% attributable to Texas Royalty properties are located in the Wasson and Yates fields. Detailed information concerning the number of wells on royalty properties is not generally available to the owners of royalty interests. Consequently, an accurate count of the number of wells located on the Texas Royalty properties cannot readily be obtained.

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

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

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

Well Count and Acreage Summary. The following table shows as of December 31, 2011, the gross and net producing wells and acres for the BROG interests. The net wells and acres are determined by multiplying the gross wells or acres by the BROG interests owner s working interest in the wells or acres. Similar information is not available for the Riverhill Energy interests. There is no undeveloped acreage on the Waddell Ranch properties.

	Number of Wells		**Acres**	
	Gross	**Net**	**Gross**	**Net**
BROG Interests	1,276	577	76,922	33,246

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OIL AND GAS PRODUCTION

The Trust recognizes production during the month in which the related distribution is received. Production of oil and gas attributable to the Royalties and the Underlying Properties, the related average sales prices and the average production cost per unit of production attributable to the Underlying Properties for the three years ended December 31, 2011, excluding portions attributable to the adjustments discussed below, were as follows:

	Waddell Ranch Properties			Texas Royalty Properties			Total		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Royalties:									
Production									
Oil (barrels)	293,983	369,392	272,734	277,315	280,410	277,189	571,298	649,802	549,923
Gas (Mcf)	1,762,003	2,456,261	1,809,253	410,151	458,162	460,647	2,172,154	2,914,423	2,269,900
Underlying Properties:									
Production									
Oil (barrels)	639,963	705,266	753,419	311,698	314,118	325,507	951,661	1,019,384	1,078,926
Gas (Mcf)	3,830,913	4,715,917	5,113,378	462,179	513,901	541,511	4,293,092	5,229,918	5,654,889
Average Sales Price									
Oil/barrel	$ 88.41	$ 73.30	$ 54.62	$ 89.11	$ 74.02	$ 51.76	$ 88.75	$ 73.61	$ 53.18
Gas/Mcf	7.43	6.63	4.56	10.38	8.87	6.38	7.98	6.98	4.93
Average Production Cost									
Oil/barrel	$ 24.22	$ 20.09	$ 12.70	$ 8.59	$ 6.49	N/A	$ 19.10	$ 15.88	N/A
Gas/Mcf	2.08	1.89	1.14	1.18	.98	N/A	1.98	1.80	N/A

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

Waddell Ranch properties lease operating expense for 2011 was $45.7 million (gross) and $19.3 million (net). The lease operating expense increased 18.6% from 2010 to 2011 primarily because of increased prices, unusually high amount of road repairs and transition costs. Waddell Ranch lifting cost on a barrel of oil equivalent (BOE) basis was $13.85/bbl as compared to $11.56 in 2010 and $11.04 in 2009.

PRICING INFORMATION

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

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

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

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OIL AND GAS RESERVES

The following are definitions adopted by the Securities and Exchange Commission (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.

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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.

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

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

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Cawley, Gillespie & Associates, Inc. s reports are attached as exhibits to this Form 10-K. The following table presents a reconciliation of proved reserve quantities from January 1, 2009 through December 31, 2011 (in thousands):

	Waddell Ranch Properties		Texas Royalty Properties		Total	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
January 1, 2009	2,350	14,355	3,510	6,309	5,860	20,664
Extensions, discoveries, and other additions	95	249			95	249
Revisions of previous estimates	177	370	(85)	(615)	92	(245)
Production	(273)	(1,809)	(279)	(457)	(552)	(2,266)
December 31, 2009	2,349	13,165	3,146	5,237	5,495	18,402
Extensions, discoveries, and other additions	121	236			121	236
Revisions of previous estimates	876	5,947	335	789	1,211	6,736
Production	(369)	(2,456)	(280)	(458)	(649)	(2,914)
December 31, 2010	2,977	16,892	3,201	5,568	6,178	22,460
Extensions, discoveries, and other additions	213	1,956			213	1,956
Revisions of previous estimates	237	(415)	175	(431)	412	(846)
Production	(324)	(1,942)	(277)	(410)	(601)	(2,352)
December 31, 2011	3,103	16,491	3,099	4,727	6,202	21,218

Estimated quantities of proved reserves and net cash flow as of December 31, 2011 are as follows:

	Waddell Ranch Properties			
	Oil (Mstb)	Gas (Mcf)	Net Cash Flow, M$	10% Disc. Cash Flow, M$
Proved Developed Producing	2,651	13,366	$ 326,363	$ 199,788
Proved Developed Non-Producing	400	3,111	$ 57,012	$ 25,535
Proved Developed	3,051	16,477	$ 383,375	$ 225,323
Proved Undeveloped	52	14	$ 4,650	$ 1,417
Total Proved	3,103	16,491	$ 388,025	$ 226,740

	Texas Royalty Properties			
	Oil (Mstb)	Gas (Mcf)	Net Cash Flow, M$	10% Disc. Cash Flow, M$
Proved Developed Producing	3,099	4,727	$ 318,140	$ 153,621
Proved Developed	3,099	4,727	$ 318,140	$ 153,621
Total Proved	3,099	4,727	$ 318,140	$ 153,621

	Total Waddell Ranch Plus Texas Royalty Properties			
	Oil (Mstb)	Gas (Mcf)	Net Cash Flow, M$	10% Disc. Cash Flow, M$
Proved Developed Producing	5,750	18,093	$ 644,503	$ 353,409
Proved Developed Non-Producing	400	3,111	$ 57,012	$ 25,535
Proved Developed	6,150	21,204	$ 701,515	$ 378,944
Proved Undeveloped	52	14	$ 4,650	$ 1,417
Total Proved	6,202	21,218	$ 706,165	$ 380,361

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

	Oil (Barrels)	Gas (Mcf)
Proved Developed Reserves:		
January 1, 2009	5,662	20,664
December 31, 2009	5,429	18,220
December 31, 2010	6,160	22,422
December 31, 2011	6,150	21,204

The Financial Accounting Standards Board requires supplemental disclosures for oil and gas producers based on a standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities. Under this disclosure, future cash inflows are computed by applying the average prices during the 12-month period prior to fiscal year-end, determined as an unweighted arithmetic average of the first-day-of-the-month benchmark price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. Future price changes are only considered to the extent provided by contractual arrangements in existence at year end. The standardized measure of discounted future net cash flows is achieved by using a discount rate of 10% a year to reflect the timing of future cash flows relating to proved oil and gas reserves.

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

The 2011, 2010 and 2009 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):

		Waddel Ranch Properties			Texas Royalty Properties			Total	
	2011	2010	2009	2011	2010	2009	2011	2010	2009
January 1	$ 192,014	$ 116,258	$ 96,962	$ 132,312	$ 94,949	$ 81,765	$ 324,326	$ 211,207	$ 178,727
Extensions, discoveries, and other additions	16,878	5,230	3,371	0	0	0	16,878	5,230	3,371
Accretion of discount	19,201	11,626	9,696	13,231	9,495	8,176	32,432	21,121	17,872
Revisions of previous estimates and other	35,508	100,396	28,395	35,799	51,637	21,800	71,307	152,033	50,195
Royalty income	(36,861)	(41,496)	(22,166)	(27,721)	(23,769)	(16,792)	(64,582)	(65,265)	(38,958)
December 31	$ 226,740	$ 192,014	$ 116,258	$ 153,621	$ 132,312	$ 94,949	$ 380,361	$ 324,326	$ 211,207

Average oil and gas prices of $96.19 per barrel and $4.11 per Mcf were used to determine the estimated future net revenues from both the Waddell Ranch properties and the Texas Royalty properties, respectively, at December 31, 2011. The upward revisions of both reserves and discounted future net cash flows for the Waddell Ranch properties and the Texas Royalty properties are primarily due to stronger pricing for oil.

Average oil and gas prices of $79.43 per barrel and $4.37 per Mcf were used to determine the estimated future net revenues from the Waddell Ranch properties and the Texas Royalty properties, respectively, at December 31, 2010. The upward revisions of both reserves and discounted future net cash flows for the Waddell Ranch properties and the Texas Royalty properties were primarily due to stronger pricing for oil and gas.

Average oil and gas prices of $55.87 and $55.38 per barrel and $4.49 and $6.27 per Mcf, respectively, were used to determine the estimated future net revenues from the Waddell Ranch properties and the Texas Royalty properties, respectively, at December 31, 2009. The upward revisions of both reserves and discounted future net cash flows for the Waddell Ranch properties and the Texas Royalty properties were primarily due to an increase in oil and gas prices from 2008 to 2009.

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The following presents estimated future net revenue and the present value of estimated future net revenue attributable to the Royalties, for each of the years ended December 31, 2011, 2010 and 2009 (in thousands):

	2011		2010		2009	
	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	$ 388,025	$ 226,740	$ 319,363	$ 192,014	$ 181,075	$ 116,258
Texas Royalty properties	318,140	153,621	278,510	132,312	197,736	94,949
Total	$ 706,165	$ 380,361	$ 597,873	$ 324,326	$ 378,811	$ 211,207

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

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

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

REGULATION

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

Exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulation includes requiring permits for the drilling 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, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. Natural gas and oil operations are also subject to various conservation laws and regulations that regulate the size of drilling and spacing units or proration units and the density of wells which may be drilled and unitization or pooling of oil and gas properties. In addition, state conservation laws establish maximum allowable production from natural gas and oil wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the 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

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Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, to direct the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce, and to significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or the FERC rules, regulations or orders thereunder. Wellhead sales of domestic natural gas are not subject to regulation. Consequently, sales of natural gas may be made at market prices, subject to applicable contract provisions.

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

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

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

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

State Regulation

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

Environmental Regulation

Companies in the oil and gas industry are subject to stringent and complex federal, 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 or underground injection activities; the restriction of the types, quantities and concentrations of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from operations including waste generation, air emissions, water discharges and current and historical waste disposal practices. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of the operations. Under certain environmental laws and regulations, the operators of the Underlying Properties could also be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination, in either case, whether at a drill site or a waste disposal facility, regardless of whether the operators were responsible for the release or contamination or if the operations were in compliance with all applicable laws at the time those actions were taken.

In addition, climate change has become the subject of an important public policy debate and the basis for new legislation proposed by the United States Congress and certain states. Some states have adopted climate change statutes and regulations. The United States Environmental Protection Agency (the EPA) has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and required reporting by regulated facilities by September 30, 2011 and annually thereafter. On November 30, 2010, the EPA published a final rule that sets forth reporting requirements for the petroleum and natural gas industry and requires persons that hold state drilling permits that emit 25,000 metric tons or more of carbon dioxide equivalent per year to report annually carbon dioxide, methane and nitrous oxide emissions from certain sources beginning on March 31, 2012. But on August 4, 2011, the EPA published a proposed rule containing technical amendments to certain greenhouse gas reporting requirements that included a six-month extension for reporting greenhouse gas emissions from petroleum and natural gas industry sources. Beyond measuring and reporting, the EPA issued an Endangerment Finding under Section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of future generations. The EPA indicated that it will use data collected through the reporting rules to decide whether to promulgate future greenhouse gas emission limits. On July 28, 2011, the EPA proposed four new regulations that, if finalized, would establish new source performance standards for volatile organic compounds (VOCs) and sulfur dioxide and establish an air toxic standard for oil and natural gas production, transmission, and storage. Limiting emissions of VOCs will have the co-benefit of also limiting methane, a greenhouse gas. The proposed regulations would apply to wells that are hydraulically fractured, or refractured, and to storage tanks and other equipment, and limit methane emissions from those sources. The EPA is expected to take final action on the proposed regulations by April 2012.

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. Hydraulic fracturing has historically been regulated by state oil and natural gas commissions. Recently, however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act (the SDWA). The EPA has begun the process of drafting guidance documents related to this newly asserted regulatory authority, which could include a broad definition of diesel that would cover a variety of oils that are not diesel but that have similar carbon-chain molecules. The EPA also plans to investigate the treatment of wastewater from hydraulic fracturing for the purpose of setting new standards for discharges from natural gas drilling to publicly owned treatment works. In addition, certain other governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices, including a four-year study by the EPA expected to be completed in 2014. These on-going or proposed reviews, depending on their scope and results, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory programs.

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

Other Regulation

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

Item 3. ***Legal Proceedings***

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

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Item 4. ***Mine Safety Disclosures***

This Item is not applicable to the Trust.

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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. Quarterly high and low sales prices and the aggregate amount of monthly distributions paid each quarter during the Trust s two most recent years were as follows:

	Sales Price		Distributions
2011	**High**	**Low**	**Paid**
First Quarter	$ 23.09	$ 19.40	$ .353128
Second Quarter	22.65	19.50	.383959
Third Quarter	23.40	19.41	.316031
Fourth Quarter	20.90	18.01	.307330
Total for 2011			$ 1.360448

			Distributions
2010	**High**	**Low**	**Paid**
First Quarter	$ 17.99	$ 14.00	$ .345536
Second Quarter	19.99	14.36	.385869
Third Quarter	19.80	17.00	.340977
Fourth Quarter	23.74	19.57	.303247
Total for 2010			$ 1.375629

Approximately 1,284 Unit holders of record held the 46,608,796 Units of the Trust at February 29, 2012.

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

Item 6. *Selected Financial Data*

	For the Year Ended December 31,				
	2011	**2010**	**2009**	**2008**	**2007**
Royalty income	$ 64,582,861	$ 65,265,303	$ 38,958,112	$ 112,341,696	$ 68,382,820
Distributable income	$ 63,409,123	$ 64,116,670	$ 37,695,948	$ 111,458,507	$ 67,619,230
Distributable income per Unit	$ 1.36	$ 1.38	$ .81	$ 2.39	$ 1.45
Distributions per Unit	$ 1.36	$ 1.38	$ .81	$ 2.39	$ 1.45
Total assets, December 31	$ 5,619,522	$ 5,552,130	$ 6,563,134	$ 6,318,009	$ 9,467,142

Computation of Royalty Income Received by the Trust

The Trust s royalty income is computed as a percentage of the net profit from the operation of the properties in which the Trust owns net overriding royalty interests. The percentages of net profits are 75% and 95% in the cases of the Waddell Ranch properties and the Texas Royalty properties, respectively. Royalty income received by the Trust for the five years ended December 31, 2011, was computed as shown in the table on the next page.

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	Year Ended December 31,								
	2011		2010		2009		2008		20
Sales From the Underlying	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties	Texas Royalty Properties	Waddell Ranch Properties
	$ 56,244,466	$ 27,614,845	$ 51,665,865	$ 22,993,347	$ 39,049,617	$ 16,859,369	$ 78,716,086	$ 34,112,890	$ 51,897,859
	27,911,119	4,789,824	31,178,053	4,556,493	22,960,089	3,438,799	54,694,736	7,831,734	41,997,463
	84,155,585	32,404,669	82,843,918	27,549,840	62,009,706	20,298,168	133,410,822	41,944,624	93,895,322
	2,302,526	1,018,930	2,006,922	687,170	1,414,303	603,461	3,365,962	1,301,428	2,241,791
	1,474,315	257,307	1,557,553	241,242	1,255,967	201,144	3,172,496	511,315	2,474,922
	205,476	0	243,369	0	167,488	0	290,737	0	169,151
xpense and Property Tax Oil	19,542,466	1,948,037	19,497,914	1,600,936	18,110,701	1,817,998	16,766,553	1,352,645	15,854,987
es	11,482,154		4,210,379		11,506,147		9,146,511		11,198,975
	35,006,937	3,224,274	27,516,137	2,529,348	32,454,606	2,622,603	32,742,259	3,165,388	31,939,826
	$ 49,148,648	$ 29,180,395	$ 55,327,781	$ 25,020,492	$ 29,555,100	$ 17,675,565	$ 100,668,563	$ 38,779,236	$ 61,955,496
yalty Interest	75%	95%	75%	95%	75%	95%	75%	95%	75%
me for Distribution	$ 36,861,486	$ 27,721,375	$ 41,495,836	$ 23,769,467	$ 22,166,325	$ 16,791,787	$ 75,501,422	$ 36,840,274	$ 46,466,622

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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, 2011

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, 2011, is reported in the following table:

	Year Ended December 31,		
Royalties	**2011**	**2010**	**2009**
Total Revenue	$ 64,582,861	$ 65,265,303	$ 38,958,112
	100%	100%	100%
Oil Revenue	48,148,810	45,950,791	28,167,940
	75%	70%	72%
Gas Revenue	16,434,051	19,314,512	10,790,172
	25%	30%	28%
Total Revenue/Unit	$ 1.385636	$ 1.400279	$ 0.835853

Royalty income of the Trust for the calendar year is associated with actual oil and gas production for the period November of the prior year through October of the current year. Oil and gas sales for 2011, 2010 and 2009 for the Royalties and the Underlying Properties, excluding portions attributable to the adjustments discussed hereafter, are presented in the following table:

	Year Ended December 31,		
Royalties	**2011**	**2010**	**2009**
Oil Sales (Bbls)	571,298	649,802	549,923
Gas Sales (Mcf)	2,172,154	2,914,423	2,269,900
Underlying Properties			
Oil			
Total Oil Sales (Bbls)	951,661	1,019,384	1,078,926
Average Per Day (Bbls)	2,607	2,637	2,885
Average Price/Bbl	$ 88.12	$ 73.24	$ 51.82
Gas			
Total Gas Sales (Mcf)	4,293,092	5,229,818	5,654,899
Average Per Day (Mcf)	11,762	13,816	14,717
Average Price/Mcf	$ 7.62	$ 6.83	$ 4.67

The average price of oil increased to $88.12 per barrel in 2011, up from $73.24 per barrel in 2010. The average price of oil in 2009 was $51.82 per barrel. In addition, the average price of gas increased from $6.83 per Mcf in 2010 to $7.62 per Mcf in 2011. The average price of gas in 2009 was $4.67 per Mcf. Oil prices have increased primarily because of world market conditions. Higher demand as a result of the ending of the U.S. recession and a slow growing global economy have caused crude oil prices to rise since the second half of 2009. Oil prices are expected to remain volatile. Decreased domestic demand for gas and an over supply of domestic gas have decreased the base price for gas. However, gas liquids values remain stronger and keep the prices of gas stronger.

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Subsequent to year end, the price of both oil and gas continued to fluctuate, giving rise to a correlating adjustment of the respective standardized measure of discounted future net cash flows. As of February 22, 2012, NYMEX posted oil prices were approximately $105.84 per barrel, which compared to the posted price of $96.19 per barrel, used to calculate the worth of future net revenue of the Trust s proved developed reserves, would result in a larger standardized measure of discounted future net cash flows for oil. As of February 22, 2012, NYMEX posted gas prices were $2.63 per million British thermal units. The use of such price, as compared to the posted price of $4.11 per million British thermal units, used to calculate the future net revenue of the Trust s proved developed reserves would result in a smaller standardized measure of discounted future net cash flows for gas.

Since the oil and gas sales attributable to the Royalties are based on an allocation formula that is dependent on such factors as price and cost (including capital expenditures), production amounts do not necessarily provide a meaningful comparison. Total oil production decreased approximately 6.6% from 2010 to 2011 primarily due to a natural production decline of the properties. Total gas production decreased approximately 17.9% from 2009 to 2010 primarily due to withholding by ConocoPhillips of proceeds from two monthly distributions related to a claimed overpayment for prior periods, as discussed more fully below.

On May 2, 2011, ConocoPhillips, as the parent company of BROG, the operator of the Waddell Ranch properties, notified the Trustee that as a result of inaccuracies in ConocoPhillips accounting and record keeping relating to the Trust s interest in proceeds from the gas plant production since January 2007, ConocoPhillips overpaid the Trust approximately $5.9 million initially. ConocoPhillips informed the Trustee on September 20, 2011 that it was withholding $4,068,067 (all of the Waddell Ranch portion of the September, 2011 proceeds, which would be reflective of July, 2011 production, of approximately 29,796 bbls of oil and 180,425 mcf of gas) in order to recoup this claim. This affected the Trust s distribution declared September 20, 2011 and paid October 17, 2011. ConocoPhillips also withheld $474,480 from the proceeds for October, 2011, which ConocoPhillips has informed the Trustee completes the recoupment. ConocoPhillips has indicated that these two recoupments will satisfy the initial claim of $5.9 million. Additionally, ConocoPhillips informed the Trustee that beginning with the June 2011 distribution, proceeds to the Trust relating to the gas plant production have been adjusted to reflect ConocoPhillips calculation of the corrected interest. The Trustee is continuing to evaluate the claim.

Total capital expenditures in 2011 used in the net overriding royalty calculation were approximately $11.48 million compared to $4.2 million in 2010 and $11.5 million in 2009. During 2011, there were 4 gross (2 net) wells drilled and completed on the Waddell Ranch properties. At December 31, 2011, there were no drill wells and 13 workovers in progress on the Waddell Ranch properties.

In 2011, lease operating expense and property taxes on the Waddell Ranch properties amounted to approximately $19.5 million. In 2010, lease operating expense and property taxes on the Waddell Ranch properties amounted to approximately $19.5 million, which amount was higher than 2009 by $1.4 million.

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

During 2011, the monthly royalty receipts were invested by the Trustee until the monthly distribution date, and earned interest totaled $636. Interest income for 2010 and 2009 was $1,216 and $3,319, respectively.

General and administrative expenses in 2011 were $1,174,374 compared to $1,149,849 in 2010 and $1,265,485 in 2009, primarily due to timing of expenses.

Distributable income for 2011 was $63,409,123 or $1.360448 per Unit.

Distributable income for 2010 was $64,116,670, or $1.375635 per Unit.

Distributable income for 2009 was $37,695,948, or $.808773 per Unit.

Results of the Fourth Quarters of 2011 and 2010

Royalty income received by the Trust for the fourth quarter of 2011 amounted to $14,505,984 or $.311228 per Unit. For the fourth quarter of 2010, the Trust received royalty income of $14,296,119 or $.306726 per Unit. Interest income for the fourth quarter of 2011 amounted to $115 compared to $407 for the fourth quarter of 2010. The decrease in interest income can be attributed primarily to a decrease of funds available. General and administrative expenses totaled $181,744 for the fourth quarter of 2011 compared to $162,457 for the fourth quarter of 2010. The increase in expenses related to an increase of professional expenses.

Royalty income for the Trust for the fourth quarter is associated with actual oil and gas production during August through October from the Underlying Properties. Oil and gas sales attributable to the Royalties and the Underlying Properties for the quarter and the comparable period for 2010 are as follows:

	Fourth Quarter	
	2011	2010
Royalties		
Oil Sales (Bbls)	138,946	142,965
Gas Sales (Mcf)	464,004	622,139
Underlying Properties		
Total Oil Sales (Bbls)	258,754	242,638
Average Per Day (Bbls)	2,813	2,637
Average Price/Bbls	$ 83.41	$ 74.30
Total Gas Sales (Mcf)	1,080,947	1,271,050
Average Per Day (Mcf)	11,749	13,816
Average Price/Mcf	$ 7.68	$ 6.46

The posted price of oil increased for the fourth quarter of 2011 compared to the fourth quarter of 2010, resulting in an average price per barrel of $83.41 compared to $74.30 in the same period of 2010. The average price of gas increased for the fourth quarter of 2011 compared to the same period in 2010, resulting in an average price per Mcf of $7.68 compared to $6.46 in the fourth quarter of 2010.

The Trustee has been advised that oil sales decreased in the fourth quarter of 2011 compared to the same period in 2010 primarily due to market demand and natural decline of production. Gas sales from the Underlying Properties decreased in the fourth quarter of 2011 compared to the same period in 2010 due to market demands. Proceeds to the Trust were reduced by $474,480 withheld by ConocoPhillips with respect to its claimed overpayment, as discussed in more detail above.

The Trust has been advised that no wells were drilled and completed during the three months ended December 31, 2011, and there were 13 wells in progress.

Use of Estimates

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

Impairment

The Trustee routinely reviews its royalty interests in oil and gas properties for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. If an impairment event occurs and it is determined that the carrying value of the Trust s royalty interests may not be recoverable, an impairment will be recognized as measured by the amount by which the carrying amount of the royalty interests exceeds the fair value of these assets, which would likely be measured by discounting projected cash flows. There is no impairment of the assets as of December 31, 2011.

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Critical Accounting Policies and Estimates

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

1. Basis of Accounting

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

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

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

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

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

The financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) because revenues are not accrued in the month of production and certain cash reserves may be established for contingencies which would not be accrued in financial statements prepared in accordance with GAAP. Amortization of the Royalties calculated on a unit-of-production basis is charged directly to trust corpus. This comprehensive basis of accounting other than GAAP corresponds to the accounting permitted for royalty trusts by the U.S. Securities and Exchange Commission as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

2. Revenue Recognition

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

3. Reserve Disclosure

Independent petroleum engineers estimate the net proved reserves attributable to the Royalty Interests. Estimates of future net revenues from proved reserves have been prepared using average 12-month oil and gas prices, determined as an unweighted arithmetic average of the first-day-of-the-month benchmark price for each month within the 12-month period preceding the end of the most recent fiscal year, unless prices are defined by contractual arrangements. The standardized measure of discounted future net cash flows is achieved by using a discount rate of 10% a year to reflect the timing of future cash flows relating to proved oil and gas reserves. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates and related costs. Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and the timing of development of non-producing reserves. Such reserve estimates are subject to change as market conditions change.

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

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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 accounting pronouncements that are expected to have a significant impact on the Trust s financial statements.

Off-Balance Sheet Arrangements.

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

Tabular Disclosure of Contractual Obligations.

Contractual Obligations	Total	Less than 1 Year	Payments Due by Period 1 - 3 Years	3 - 5 Years	More than 5 Years
Distribution payable to Unit holders	$ 4,727,946	$ 4,727,946	$ 0	$ 0	$ 0
Total	$ 4,727,946	$ 4,727,946	$ 0	$ 0	$ 0

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Unit Holders of Permian Basin Royalty Trust and

Bank of America, N.A, Trustee:

We have audited the accompanying statements of assets, liabilities, and trust corpus of Permian Basin Royalty Trust (the Trust) as of December 31, 2011 and 2010, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2011. 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 conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 3 to the financial statements, these financial statements have been 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.

In our opinion, such financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of the Trust at December 31, 2011 and 2010, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2011, on the basis of accounting described in Note 3.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust s internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 2, 2012 expressed an unqualified opinion on the Trustee s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Austin, TX

March 2, 2012

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PERMIAN BASIN ROYALTY TRUST

FINANCIAL STATEMENTS

STAT EMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

	December 31, 2011	December 31, 2010
ASSETS		
Cash and Short-term Investments	$ 4,727,946	$ 4,580,923
Net Overriding Royalty Interests in Producing Oil and Gas Properties Net (Notes 2 and 3)	891,576	971,207
Total	$ 5,619,522	$ 5,552,130
LIABILITIES AND TRUST CORPUS		
Distribution Payable to Unit Holders	$ 4,727,946	$ 4,580,923
Trust Corpus 46,608,796 Units of Beneficial Interest Authorized and Outstanding	891,576	971,207
Total	$ 5,619,522	$ 5,552,130

STATEMENTS OF DISTRIBUTABLE INCOME

	For the years ended December 31, 2011	2010	2009
Royalty Income (Notes 2 and 3)	$ 64,582,861	$ 65,265,303	$ 38,958,112
Interest Income	636	1,216	3,319
	64,583,497	65,266,519	38,961,431
Expenditures General and Administrative	1,174,374	1,149,849	1,265,483
Distributable Income	$ 63,409,123	$ 64,116,670	$ 37,695,948
Distributable Income per Unit (46,608,796 Units)	$ 1.36	$ 1.38	$ .81
Distributions per Unit	$ 1.36	$ 1.38	$ .81

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

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STATEMENTS OF CHANGES IN TRUST CORPUS

	For the years ended December 31, 2011	2010	2009
Trust Corpus, Beginning of Year	$ 971,207	$ 1,079,986	$ 1,170,793
Amortization of Net Overriding Royalty Interests (Notes 2 and 3)	(79,631)	(108,779)	(90,807)
Distributable Income	63,409,123	64,116,670	37,695,948
Distributions Declared	(63,409,123)	(64,116,670)	(37,695,948)
Trust Corpus, End of Year	$ 891,576	$ 971,207	$ 1,079,986

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

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NOTES TO FINANCIAL STATEMENTS

1. Trust Organization and Provisions

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

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

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

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

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

In 2007 the Bank of America private wealth management group officially became known as U.S. Trust, Bank of America Private Wealth Management. The legal entity that serves as Trustee of the Trust did not change.

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 2).

2. Net Overriding Royalty Interests and Distribution to Unit Holders

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

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

The initial carrying value of the Royalties ($10,975,216) represented Southland Royalty Company s historical net book value at the date of the transfer to the Trust. Accumulated amortization as of December 31, 2011 and 2010 was $10,083,640 and $10,004,009, respectively.

3. Accounting Policies

Basis of Accounting

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

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

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

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

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

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

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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 is no impairment of the assets as of December 31, 2011.

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.

4. New Accounting Pronouncements

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

5. Federal Income Tax

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

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. U.S. Trust, Bank of America Private Wealth Management, EIN: 56-0906609, 901 Main Street, 17th Floor, Dallas, Texas 75202, telephone number (214) 209-2400, 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-permianbasintrust.com. Notwithstanding the foregoing, the middlemen holding Trust Units on behalf of Unit holders, and not the Trustee of the Trust, are solely responsible for complying with the information reporting requirements under the U.S. Treasury Regulations with respect to such Trust Units, including the issuance of IRS Forms 1099 and certain written tax statements. Unit holders whose Trust Units are held by middlemen should consult with such middlemen regarding the information that will be reported to them by the middlemen with respect to the Trust Units.

Because the Trust is a grantor trust for federal tax purposes, each Unit holder is taxed directly on his proportionate share of income, deductions and credits of the Trust consistent with each such Unit holder s taxable year and method of accounting and without regard to the taxable year or method of accounting employed by the Trust. The income of the Trust consists primarily of a specified share of the proceeds from the sale of oil and gas produced from the Underlying Properties. During 2011, the Trust earned interest income on funds held for distribution and made adjustments to the cash reserve maintained for the payment of contingent and future obligations of the Trust.

The deductions of the Trust consist of severance taxes and administrative expenses. In addition, each Unit holder is entitled to depletion deductions because the Royalties constitute economic interests in oil and gas properties for federal income tax purposes. Each Unit holder is entitled to amortize the cost of the Units through cost depletion over the life of the Royalties or, if greater, through percentage depletion equal to 15 percent of gross income. Unlike cost depletion, percentage depletion is not

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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 would normally compute both percentage depletion and cost depletion from each property and claim the larger amount as a deduction on their income tax returns. The Trustee has estimated the cost depletion for January through December 2011, and it appears that percentage depletion will exceed cost depletion for some of the Unit holders.

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 taxpayer generally must recapture the amount deducted for depletion as ordinary income (to the extent of gain realized on the disposition of the property). This depletion recapture rule applies to any disposition of property that was placed in service by the taxpayer after December 31, 1986. Detailed rules set forth in Sections 1.1254-1 through 1.1254-6 of the U.S. Treasury Regulations govern dispositions of property after March 13, 1995. The Internal Revenue Service likely will take the position that a Unit holder who purchases a Unit subsequent to December 31, 1986 must recapture depletion upon the disposition of that Unit.

Individuals may incur expenses in connection with the acquisition or maintenance of Trust Units. 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.

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

Unit holders of record will continue to receive an individualized tax information letter for each of the quarters ending March 31, June 30 and September 30, 2012, and for the year ending December 31, 2012. Unit holders owning Units in nominee may obtain monthly tax information from the Trustee upon request. See discussion above regarding certain reporting requirements imposed upon middlemen under U.S. Treasury Regulations because the Trust is considered a WHIFT for federal income tax purposes.

The Tax consequences to a Unit holder of the ownership and sale of Units will depend in part on the Unit holder s tax circumstances. Unit holders should consult their tax advisors about the federal tax consequences relating to owning the Units in the Trust.

6. Proved Oil and Gas Reserves (Unaudited)

Reserve Quantities

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

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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)	Total Gas (Mcf)
January 1, 2009	5,860	20,664
Extensions, discoveries, and other additions	95	249
Revisions of previous estimates	92	(245)
Production	(552)	(2,266)
December 31, 2009	5,495	18,402
Extensions, discoveries, and other additions	121	236
Revisions of previous estimates	1,211	6,736
Production	(649)	(2,914)
December 31, 2010	6,178	22,460
Extensions, discoveries, and other additions	213	1,956
Revisions of previous estimates	412	(846)
Production	(601)	(2,352)
December 31, 2011	6,202	21,218

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

	Oil (Barrels)	Gas (Mcf)
Proved Developed Reserves:		
January 1, 2009	5,662	20,664
December 31, 2009	5,429	18,220
December 31, 2010	6,160	22,422
December 31, 2011	6,202	21,218

Disclosure of a Standardized Measure of Discounted Future Net Cash Flows

The following is a summary of a standardized measure (in thousands) of discounted future net cash flows related to the Trust s total proved oil and gas reserve quantities. Information presented is based upon valuation of proved reserves by using discounted cash flows based upon average oil and gas prices ($96.19 per bbl and $4.11 per Mcf, respectively) during the 12-month period prior to the fiscal year-end, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions and severance and ad valorem taxes, if any, and economic conditions, discounted at the required rate of 10 percent. As the Trust is not subject to taxation at the trust level, no provision for income taxes has been made in the following disclosure. Trust prices may differ from posted 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,	2011	2010	2009
Future net cash inflows	$706,165	$597,873	$378,811

Discount of future net cash flows @ 10%	(325,804)	(273,547)	(167,604)
Standardized measure of discounted future net cash inflows	$380,361	$324,326	$211,207

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The change in the standardized measure of discounted future net cash flows for the years ended December 31, 2011, 2010 and 2009 is as follows (in thousands):

		Total	
	2011	2010	2009
January 1	$ 324,326	$ 211,207	$ 178,727
Extensions, discoveries, and other additions	16,878	5,230	3,371
Accretion of discount	32,432	21,121	17,872
Revisions of previous estimates and other	71,307	152,033	50,195
Royalty income	(64,582)	(65,265)	(38,958)
December 31	$ 380,361	$ 324,326	$ 211,207

Subsequent to year end, the price of both oil and gas continued to fluctuate, giving rise to a correlating adjustment of the respective standardized measure of discounted future net cash flows. As of February 22, 2012, NYMEX posted oil prices were approximately $105.84 per barrel, which compared to the posted price of $96.19 per barrel, used to calculate the worth of future net revenue of the Trust s proved developed reserves, would result in a larger standardized measure of discounted future net cash flows for oil. As of February 22, 2012, NYMEX posted gas prices were $2.63 per million British thermal units. The use of such price, as compared to the posted price of $4.11 per million British thermal units, used to calculate the future net revenue of the Trust s proved developed reserves would result in a smaller standardized measure of discounted future net cash flows for gas.

7. Quarterly Schedule of Distributable Income (Unaudited)

The following is a summary of the unaudited quarterly schedule of distributable income for the two years ended December 31, 2011 (in thousands, except per Unit amounts):

2011	Royalty Income	Distributable Income	Distributable Income and Distribution Per Unit
First Quarter	$ 16,798	$ 16,459	$ .353128
Second Quarter	18,399	17,895	.383959
Third Quarter	14,879	14,729	.316031
Fourth Quarter	14,507	14,326	.307330
Total	$ 64,583	$ 63,409	$ 1.360448

2010	Royalty Income	Distributable Income	Distributable Income and Distribution Per Unit
First Quarter	$ 16,509	$ 16,105	$ .345536
Second Quarter	18,444	17,985	.385869
Third Quarter	16,016	15,893	.340977
Fourth Quarter	14,296	14,134	.303247
Total	$ 65,265	$ 64,117	$ 1.375629

8. Subsequent Events

Subsequent to December 31, 2011, the Trust declared the following distributions:

Monthly Record Date	Payment Date	Distribution per Unit
January 31, 2012	February 14, 2012	$ .125910
February 29, 2012	March 14, 2012	$ .164216

9. State Tax Considerations

All revenues from the Trust are from sources within Texas, which has no individual income tax. Texas imposes a franchise tax at a rate of 1% on gross revenues less certain deductions, as specifically set forth in the Texas franchise tax statutes. Entities subject to tax generally include trusts unless otherwise exempt and most other types of entities that provide limited liability protection. Trusts that receive at least 90% of their federal gross income from designated 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 should 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 considered a taxable entity under the Texas franchise tax would generally be required to include its portion of Trust revenues in its own Texas franchise tax computation. This revenue would be 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.

Each Unit holder is urged to consult his own tax advisor regarding the requirements for filing state tax returns.

10. Contingencies

On May 2, 2011, ConocoPhillips, as the parent company of BROG, the operator of the Waddell Ranch properties, notified the Trustee that as a result of inaccuracies in ConocoPhillips accounting and record keeping relating to the Trust s interest in proceeds from the gas plant production since January 2007, ConocoPhillips overpaid the Trust approximately $5.9 million initially. ConocoPhillips informed the Trustee on September 20, 2011 that it was withholding $4,068,067 (all of the Waddell Ranch portion of the September, 2011 proceeds, which would be reflective of July, 2011 production, of approximately 29,796 bbls of oil and 180,425 mcf of gas) in order to recoup this claim. This affected the Trust s distribution declared September 20, 2011 and paid October 17, 2011. ConocoPhillips also withheld $474,480 from the proceeds for October, 2011, which ConocoPhillips has informed the Trustee completes the recoupment. ConocoPhillips has indicated that these two recoupments will satisfy the initial claim of $5.9 million. Additionally, ConocoPhillips informed the Trustee that beginning with the June 2011 distribution, proceeds to the Trust relating to the gas plant production have been adjusted to reflect ConocoPhillips calculation of the corrected interest. The Trustee is continuing to evaluate the claim.

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Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***
None.

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

As of the end of the period covered by this report, the Trustee carried out an evaluation of the effectiveness of the design and operation of the Trust s disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 promulgated under the Securities Exchange Act of 1934, as amended. Based upon that evaluation, the Trustee concluded that the Trust s disclosure controls and procedures are effective in recording, processing, summarizing and reporting, on a timely basis, 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, and are effective in ensuring that information required to be disclosed by the Trust in the reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to the Trustee to allow timely decisions regarding required disclosure. In its evaluation of disclosure controls and procedures, the Trustee has relied, to the extent considered reasonable, on information provided by Burlington Resources Oil & Gas Company, LP, the owner of the Waddell Ranch properties, and Riverhill Energy Corporation, the owner of the Texas Royalty properties.

Changes in Internal Control over Financial Reporting

There has not been any change in the Trust s internal control over financial reporting during the fourth quarter of 2011 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. The Trustee conducted an evaluation of the effectiveness of the Trust s internal control over financial reporting modified cash basis (internal control over financial reporting) based on the criteria established in *Internal Control-Integrated Framework* 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*, the Trustee concluded that the Trust s internal control over financial reporting was effective as of December 31, 2011. The independent registered public accounting firm of Deloitte & Touche LLP, as auditors of the statements of assets, liabilities, and trust corpus, and the related statements of distributable income and changes in trust corpus for the year ended December 31, 2011, has issued an attestation report on the Trust s internal control over financial reporting, which is included herein.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Unit Holders of Permian Basin Royalty Trust and

Bank of America, N.A., Trustee

We have audited the internal control over financial reporting of Permian Basin Royalty Trust (the Trust) as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Trustee is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Trustee s Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Trust s internal control over financial reporting based on our audit.

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

A trust s internal control over financial reporting is a process designed by, or under the supervision of, the Trustee, or persons performing similar functions, and effected by the Trustee, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America and is described in Note 3 to the Trust s financial statements. A trust s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the modified cash basis of accounting discussed above, and that receipts and expenditures of the Trust are being made only in accordance with authorizations of the Trustee; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Trust s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the statements of assets, liabilities and trust corpus of the Trust as of December 31, 2011, and the related statements of distributable income and changes in trust corpus for the year ended December 31, 2011, which financial statements have been prepared on the modified cash basis of accounting as described in Note 3 to such financial statements, and our report dated March 2, 2012 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Austin, TX

March 2, 2012

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Item 9B. ***Other Information.***
None.

PART III

Item 10. ***Directors and Executive Officers of the Registrant***

DIRECTORS AND OFFICERS

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

AUDIT COMMITTEE AND NOMINATING COMMITTEE

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

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Securities Exchange At 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 2011, no person who was a beneficial owner of more than ten percent the Trust s Units failed to file on a timely basis any report required by Section 16(a).

CODE OF ETHICS

Because the Trust has no employees, it does not have a code of ethics. Employees of the Trustee, Bank of America Private Wealth Management must comply with the bank s code of ethics, a copy of which will be provided to Unit holders, without charge, upon request made to U.S. Trust, Bank of America Private Wealth Management, Trustee, P.O. Box 830650, Dallas, Texas 75202, Attention: Ron Hooper.

Item 11. ***Executive Compensation***
During the years ended December 31, 2011, 2010 and 2009, the Trustee received total remuneration as follows:

Name of Individual or Number of Persons in Group	**Cash Compensation**	**Year**
Bank of America, N.A., Trustee	$ 70,039(1)	2011
	$ 62,380(1)	2010
	$ 68,976(1)	2009

(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.

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COMPENSATION COMMITTEE

Because the Trust has no directors, it does not have a compensation committee, and the Trust has not engaged any consultants to provide advice or recommendations on the amount or form of compensation.

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 Trustee is not aware of any person owning beneficially more than 5% of the outstanding Units of the Trust as of March 2, 2012.

(b) *Security Ownership of Management*. The Trustee does not beneficially own any securities of the Trust. In various fiduciary capacities, Bank of America, N.A. owned as of March 2, 2012, an aggregate of 1,416,458 Units with no right to vote all of these Units, shared right to vote none of these Units and sole right to vote none of these Units. Bank of America, N.A., disclaims any beneficial interests in these Units. The number of Units reflected in this paragraph includes Units held by all branches of Bank of America, N.A.

(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, 2011, 2010 and 2009 and Item 12(b) for information concerning Units owned by Bank of America, N.A. in various fiduciary capacities.

Item 14. ***Principal Accounting Fees and Services.***

Fees for services performed by Deloitte & Touche LLP for the years ended December 31, 2011 and 2010 are:

	2011	**2010**
Audit Fees	$ 88,000	$ 83,000
Audit-related fees		
Tax fees		
All other fees		
Total	$ 88,000	$ 83,000

As referenced in Item 10 above, the Trust has no audit committee, and as a result, has no audit committee pre-approval policy with respect to fees paid to Deloitte & Touche LLP.

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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:

2. *Financial Statement Schedules*

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

3. *Exhibits*

Exhibit Number	Exhibit
(4)(a)	Permian Basin Royalty Trust Indenture dated November 3, 1980, between Southland Royalty Company and The First National Bank of Fort Worth (now Bank of America, N.A.), as Trustee, heretofore filed as Exhibit (4)(a) 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.*
(b)	Net Overriding Royalty Conveyance (Permian Basin Royalty Trust) from Southland Royalty Company to The First National Bank of Fort Worth (now Bank of America, N.A.), 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.*
(c)	Net Overriding Royalty Conveyance (Permian Basin Royalty Trust Waddell Ranch) from Southland Royalty Company to The First National Bank of Fort Worth (now Bank of America, N.A.), 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.*
(10)(a)	Underwriting Agreement dated December 15, 2005 among the Permian Basin Royalty Trust, Burlington Resources, Inc., Burlington Resources Oil & Gas L.P. and Lehman Brothers Inc. and Wachovia Capital Markets, LLC as representatives of the several underwriters, heretofore filed as Exhibit 10.1 to the Trust s current report on Form 8-K to the Securities and Exchange Commission filed on December 19, 2005, is incorporated herein by reference.*
(b)	Underwriting Agreement dated August 2, 2005 among the Permian Basin Royalty Trust, Burlington Resources, Inc., Burlington Resources Oil & Gas L.P. and Goldman Sachs & Co. and Lehman Brothers Inc. as representatives of the several underwriters, heretofore filed as Exhibit 10.1 to the Trust s current report on Form 8-K to the Securities and Exchange Commission filed on August 8, 2005, is incorporated herein by reference.*
(c)	Underwriting Agreement dated August 17, 2006, among Permian Basin Royalty Trust, ConocoPhillips, Burlington Resources Oil & Gas Company LP and Lehman Brothers Inc. and Wachovia Capital Markets, LLC as representatives of the several underwriters heretofore filed as Exhibit 10.1 to the Trust s current report on Form 8-K to the Securities and Exchange Commission filed on

August 22, 2006, is incorporated herein by reference.*

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Exhibit Number	Exhibit
(d)	Registration Rights Agreement dated as of July 21, 2004 by and between Burlington Resources, Inc. and Bank of America, N.A., as trustee of Permian Basin Royalty Trust, heretofore filed as Exhibit 10.1 to the Trust s Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarterly period ended June 30, 2004 is incorporated herein by reference.*
(23.1)	Consent of Cawley, Gillespie & Associates, Inc., reservoir engineer.**
(31.1)	Certification required by Rule 13a-14(a)/15d-14(a).**
(32.1)	Certification required by Rule 13a-14(b)/15d-14(b) and Section 906 of the Sarbanes-Oxley Act of 2002.**
(99.1)	Report of Cawley, Gillespie & Associates, Inc., reservoir engineer.**

* A copy of this Exhibit is available to any Unit holder, at the actual cost of reproduction, upon written request to the Trustee, U.S. Trust, Bank of America Private Wealth Management, P.O. Box 830650, Dallas, Texas 75202.

** Filed herewith.

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SIGNATURE

PURSUANT TO THE REQUIREMENTS OF SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934, THE REGISTRANT HAS DULY CAUSED THIS REPORT TO BE SIGNED ON ITS BEHALF BY THE UNDERSIGNED, THEREUNTO DULY AUTHORIZED.

BANK OF AMERICA, N.A.,

TRUSTEE FOR THE

PERMIAN BASIN ROYALTY TRUST

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

Senior Vice President

Trust Administrator

Date: March 2, 2012

(The Trust has no directors or executive officers.)

INDEX TO EXHIBITS

EXHIBIT NUMBER	EXHIBIT
(4)(a)	Permian Basin Royalty Trust Indenture dated November 3, 1980, between Southland Royalty Company and The First National Bank of Fort Worth (now Bank of America, N.A.), as Trustee, heretofore filed as Exhibit (4)(a) 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.*
(b)	Net Overriding Royalty Conveyance (Permian Basin Royalty Trust) from Southland Royalty Company to The First National Bank of Fort Worth (now Bank of America, N.A.), 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.*
(c)	Net Overriding Royalty Conveyance (Permian Basin Royalty Trust Waddell Ranch) from Southland Royalty Company to The First National Bank of Fort Worth (now Bank of America, N.A.), 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.*
(10)(a)	Underwriting Agreement dated December 15, 2005 among the Permian Basin Royalty Trust, Burlington Resources, Inc., Burlington Resources Oil & Gas L.P. and Lehman Brothers Inc. and Wachovia Capital Markets, LLC as representatives of the several underwriters, heretofore filed as Exhibit 10.1 to the Trust s current report on Form 8-K to the Securities and Exchange Commission filed on December 19, 2005, is incorporated herein by reference.*
(b)	Underwriting Agreement dated August 2, 2005 among the Permian Basin Royalty Trust, Burlington Resources, Inc., Burlington Resources Oil & Gas L.P. and Goldman Sachs & Co. and Lehman Brothers Inc. as representatives of the several underwriters, heretofore filed as Exhibit 10.1 to the Trust s current report on Form 8-K to the Securities and Exchange Commission filed on August 8, 2005, is incorporated herein by reference.*
(c)	Underwriting Agreement dated August 17, 2006, among Permian Basin Royalty Trust, ConocoPhillips, Burlington Resources Oil & Gas Company LP and Lehman Brothers Inc. and Wachovia Capital Markets, LLC as representatives of the several underwriters heretofore filed as Exhibit 10.1 to the Trust s current report on Form 8-K to the Securities and Exchange Commission filed on August 22, 2006, is incorporated herein by reference.*
(d)	Registration Rights Agreement dated as of July 21, 2004 by and between Burlington Resources, Inc. and Bank of America, N.A., as trustee of Permian Basin Royalty Trust, heretofore filed as Exhibit 10.1 to the Trust s Quarterly Report on Form 10-Q to the Securities and Exchange Commission for the quarterly period ended June 30, 2004 is incorporated herein by reference.*
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(31.1)	Certification required by Rule 13a-14(a)/15d-14(a).**
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** Filed herewith.