PERMIAN BASIN ROYALTY TRUST

Annual Report & Form 10-K 2006

THE TRUST

The Permian Basin Royalty Trust's (the "Trust") principal assets are comprised of a 75% net overriding royalty interest carved out by Southland Royalty Company ("Southland") from its fee mineral interest in the Waddell Ranch properties in Crane County, Texas ("Waddell Ranch properties"), and a 95% net overriding royalty interest carved out by Southland from its major producing royalty properties in Texas ("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 royalties above are collectively referred to as the "Royalties." The properties and interests from which the Royalties were carved and which the Royalties now burden are collectively referred to as the "Underlying Properties."

The Trust has been advised that effective January 1, 1996, Southland was merged with and into Meridian Oil Inc. ("Meridian"), a Delaware corporation, with Meridian being the surviving corporation. Meridian succeeded to the ownership of all the assets, has the rights, powers, and privileges, and assumed all of the liabilities and obligations of Southland. Effective July 11, 1996, Meridian changed its name to Burlington Resources Oil & Gas Company, now Burlington Resources 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 Meridian or Southland. Further, BROG notified the Trust that, on February 14, 1997, the Texas Royalty properties that are subject to the Net Overriding Royalty Conveyance dated November 1, 1980 ("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.

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
2006	**High**	**Low**	**Paid**
First Quarter	$16.91	$14.05	$ .400354
Second Quarter	16.93	14.35	.297034
Third Quarter	17.00	15.25	.398559
Fourth Quarter	16.68	15.23	.314135
Total for 2006			$1.410082
2005	**High**	**Low**	**Paid**
First Quarter	$15.57	$12.13	$ .284149
Second Quarter	15.50	10.75	.268627
Third Quarter	17.23	14.73	.340939
Fourth Quarter	17.15	15.00	.442249
Total for 2005			$1.335964

Approximately 1,524 Unit holders of record held the 46,608,796 Units of the Trust at December 31, 2006.

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

TO UNIT HOLDERS

We are pleased to present the twenty-sixth Annual Report of the Trust. The report includes a copy of the Trust's Annual Report on Form 10-K to the Securities and Exchange Commission for the year ended December 31, 2006, without exhibits. Both the report and accompanying Form 10-K contain important information concerning the Trust's properties, including the oil and gas reserves attributable to the Royalties owned by the Trust. Production figures, drilling activity and certain other information included in this report have been provided to the Trust by BROG (formerly Meridian and Southland) and Riverhill Energy.

As more particularly explained in the Notes to the Financial Statements appearing in this report and in Item 1 of the accompanying Form 10-K, Bank of America, N.A., as Trustee, has the primary function under the Trust Indenture of collecting the monthly net proceeds attributable to the Royalties and making monthly distributions to the Unit holders, after deducting Trust administrative expenses and any amounts necessary for cash reserves.

Royalty income received by the Trustee for the year ended December 31, 2006, was $66,407,199 and interest income earned for the same period was $133,648. General and administrative expenses amounted to $825,478. A total of $65,715,369 or 1.410082 per Unit, was distributed to Unit holders during 2006. A discussion of factors affecting the distributions for 2006 may be found in the Trustee's Discussion and Analysis section of this report and the accompanying Form 10-K.

As of December 31, 2006, the Trust's proved reserves were estimated at 6,578,000 Bbls of oil and 24,130,000 Mcf of gas. The estimated future net revenues from proved reserves at December 31, 2006 amount to $468,189,000 or $10.58 per Unit. The present value of estimated future net revenues discounted at 10% at December 31, 2006 was $265,970,500 or $5.71 per Unit. The computation of future net revenues is made following guidelines prescribed by the Financial Accounting Standards Board (explained in Item 2 of the accompanying Form 10-K) based on year-end prices and costs.

As has been previously reported, Southland advised the Trust that it became operator of record of the Waddell Ranch properties on May 1, 1991. Meridian, as successor by merger, became the operator of record effective January 1, 1996. Meridian changed its name to Burlington Resources Oil & Gas Company in 1996 and again to Burlington Resources Oil & Gas Company LP in 2000. All field, technical and accounting operations, however, have been carried out by Schlumberger Technology Corporation ("STC") under the direction of BROG, and by Riverhill Capital Corporation ("Riverhill Capital").

As was previously reported, in February 1997, BROG sold its interest in the Texas Royalty properties that are subject to the Texas Royalty Conveyance to Riverhill Energy, which at the time was a wholly-owned subsidiary of Riverhill Capital and an affiliate of Coastal Management Corporation ("CMC"). Subsequently, the Trustee was advised that STC acquired all of the shares of Riverhill Capital. The Trustee has been advised that, as part of this transaction, ownership of Riverhill Energy's interests in the Texas Royalty properties referenced above remain in Riverhill Energy, which was owned by the former shareholders of Riverhill Capital. All accounting operations pertaining to the Texas Royalty properties are performed by Riverhill Energy.

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 and its accountants have estimated the cost depletion for January through December 2006, and it appears that percentage depletion will exceed cost depletion for all Unit holders.

Royalty income is generally considered portfolio income under the passive loss rules. 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, 2007, and for the year ending December 31, 2007. Unit holders owning Units in nominee name may obtain monthly tax information from the Trustee upon request.

Bank of America, N.A., Trustee

Ron E. Hooper

Ron E. Hooper
SENIOR VICE PRESIDENT

DESCRIPTION OF THE PROPERTIES

The net overriding royalty interests held by the Trust are carved out of high-quality producing oil and gas properties located primarily in West Texas. 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, 2006, is approximately 8.3 years.

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 76,922 gross acres and 33,246 net acres, containing 800 gross (353 net) productive oil wells, 205 gross (97 net) productive gas wells and 309 gross (134 net) injection wells.

Six major fields on the Waddell Ranch properties account for more than 90% 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 Andreas, which produce from depths between 2,800 and 3,400 feet. Productive from the San Andreas are the Sand Hills (Judkins) gas field and the Sand Hills (McKnight) oil field, the Dune (Grayburg/San Andreas) oil field, and the Waddell (Grayburg/San Andreas) oil field.

The Dune and Waddell oil fields are productive from both the Grayburg and San Andreas 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.

All of the major oil fields on the Waddell Ranch properties are currently being water flooded. Engineering studies and 3-D seismic evaluations on these fields indicate the potential for increased production through infill drilling, modifications of existing water flood techniques and installation of larger capacity pumping equipment. Capital expenditures for remedial and maintenance activities during 2006 totaled approximately $35.6 million.

The Texas Royalty properties, out of which the other net overriding royalty was carved, are located in 33 counties across Texas. The Texas Royalty properties consist of approximately 125 separate royalty interests containing approximately 303,000 gross (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.

BROG has informed the Trustee that the 2007 capital expenditures budget with regard to the Waddell Ranch properties should total approximately $32.4 million gross of which $18.9 million gross is attributable to drilling, $12.4 million gross to workovers and recompletions, and $1.1 million gross to facilities.

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, 2006, was computed as shown in the table on the next page.

	Year Ended December 31,									
	2006		2005		2004		2003		2002	
	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	Texas Royalty Properties
Gross Proceeds of Sales From the Underlying Properties:										
Oil Proceeds.	$51,185,185	$21,301,642	$43,967,934	$17,415,261	$32,078,721	$12,296,982	$24,418,227	$ 9,454,914	$20,543,224	$ 7,785,749
Gas Proceeds	40,386,375	5,780,321	37,531,266	5,050,206	28,746,318	3,970,231	25,255,338	3,606,615	14,861,094	2,245,648
Total.	91,571,560	27,081,963	81,499,200	22,465,467	60,825,039	16,267,213	49,673,565	13,061,529	35,404,318	10,031,397
Less:										
Severance Tax										
Oil.	2,219,552	760,043	1,806,281	675,609	1,366,942	457,308	1,045,413	350,440	863,299	302,665
Gas	2,587,606	378,513	2,319,699	325,044	1,702,937	262,673	1,632,642	228,928	813,581	159,431
Other	42,695	–	42,505	–	42,763	252,906	26,850	–	72,397	–
Lease Operating Expense and Property Tax										
Oil and Gas. . . .	13,932,289	1,454,993	12,191,168	963,563	9,391,083	894,383	10,540,850	823,331	9,424,724	933,646
Capital Expenditures	15,265,143	–	7,151,598	–	6,539,015	–	7,734,224	–	3,394,674	–
Total.	34,047,285	2,593,549	23,511,251	1,964,216	19,042,740	1,867,270	20,979,979	1,402,699	14,568,674	1,395,742
Net Profits.	57,524,275	24,488,414	57,987,949	20,501,251	41,782,299	14,399,943	28,693,586	11,658,830	20,835,643	8,635,655
Net Overriding Royalty Interest . . .	75%	95%	75%	95%	75%	95%	75%	95%	75%	95%
Royalty Income	43,143,206	23,263,993	43,490,961	19,476,189	31,336,724	13,679,946	21,520,190	11,075,888	15,626,732	8,203,872
Total Royalty Income for Distribution	$43,143,206	$23,263,993	$43,490,961	$19,476,189	$31,336,724	$13,679,946	$21,520,190	$11,075,888	$15,626,732	$ 8,203,872

DISCUSSION AND ANALYSIS

TRUSTEE'S DISCUSSION AND ANALYSIS FOR THE THREE-YEAR PERIOD ENDED DECEMBER 31, 2006

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. 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 natural gas produced for the twelve-month period ended October 31st in that calendar year.

2. Reserve Recognition

Independent petroleum engineers estimate the net proved reserves attributable to the Royalty Interests. In accordance with Statement of Financial Standards No. 69, "Disclosures About Oil and Gas Producing Activities," estimates of future net revenues from proved reserves have been prepared using year-end contractual gas prices. 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.

3. 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.

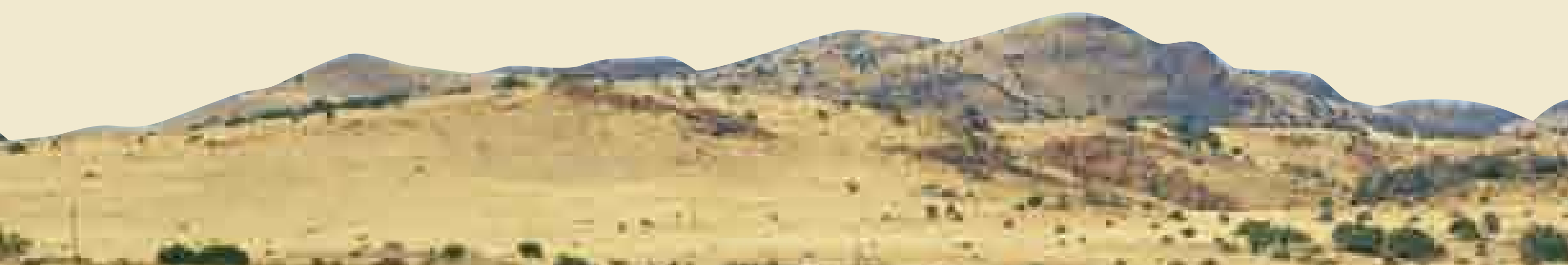
LIQUIDITY AND CAPITAL RESOURCES

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, 2006, is reported in the following table:

	Year Ended December 31,		
Royalties	**2006**	**2005**	**2004**
Total Revenue	**$66,407,199**	$62,967,150	$45,016,670
	100%	100%	100%
Oil Revenue	**42,729,342**	38,924,579	27,180,560
	64%	62%	60%
Gas Revenue	**23,677,857**	24,042,571	17,836,110
	36%	38%	40%
Total Revenue/Unit	**$ 1.424775**	$ 1.35097	$ .965841



DISCUSSION AND ANALYSIS *(continued)*

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 2006, 2005 and 2004 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	**2006**	**2005**	**2004**
Oil Sales (Bbls)	**749,949**	827,275	779,052
Gas Sales (Mcf)	**3,154,791**	3,608,778	3,245,117
Underlying Properties			
Oil			
Total Oil Sales (Bbls)	**1,221,165**	1,258,584	1,222,579
Average Per Day (Bbls)	**3,346**	3,448	3,340
Average Price/Bbl	**$ 59.36**	$ 48.77	$ 36.30
Gas			
Total Gas Sales (Mcf)	**5,973,188**	6,132,716	5,975,867
Average Per Day (Mcf)	**16,365**	16,802	16,328
Average Price/Mcf	**$ 7.73**	$ 6.94	$ 5.47

The average price of oil increased to $59.36 per barrel in 2006, up from $48.77 per barrel in 2005. The average price of oil in 2004 was $36.30 per barrel. In addition, the average price of gas increased from $6.94 per Mcf in 2005 to $7.73 per Mcf in 2006. The average price of gas in 2004 was $5.47 per Mcf.

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 3% from 2005 to 2006 primarily due to natural decline of properties. Total gas production decreased approximately 3% from 2005 to 2006 primarily due to natural decline of properties.

Total capital expenditures in 2006 used in the net overriding royalty calculation were approximately $34 million compared to $7.2 million in 2005 and $6.5 million in 2004. During 2006, there were 23 gross (11 net) wells drilled and completed on the Waddell Ranch properties. At December 31, 2006, there were 3 drill wells and 6 workovers in progress on the Waddell Ranch properties.

In 2006, lease operating expense and property taxes on the Waddell Ranch properties amounted to approximately $13.9 million, which amount was higher than 2005 by $1.7 million.

The Trustee has been advised by BROG that for the period August 1, 1993, through January 1, 2007, the oil from the Waddell Ranch was and will be sold under a competitive bid to a third party.

During 2006, the monthly royalty receipts were invested by the Trustee in U.S. Treasury securities until the monthly distribution date, and earned interest totaled $133,648. Interest income for 2005 and 2004 was $63,909 and $19,883, respectively.

General and administrative expenses in 2006 were $825,478 compared to $763,390 in 2005 and $489,810 in 2004, primarily due to increased expenses related to compliance with the Sarbanes-Oxley Act and increased Unit holder reporting.

Distributable income for 2006 was $65,715,369, or $1.410082 per Unit.

Distributable income for 2005 was $62,267,669, or $1.335964 per Unit.

Distributable income for 2004 was $44,546,743, or $.955758 per Unit.

FINANCIAL STATEMENTS

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS
DECEMBER 31, 2006 AND 2005

Assets	2006	2005
Cash and Short-term Investments	**$5,135,136**	$7,264,048
Net Overriding Royalty Interests in Producing Oil and Gas Properties – Net (Notes 2 and 3)	**1,439,214**	1,610,630
	$6,574,350	$8,874,678
Liabilities and Trust Corpus		
Distribution Payable to Unit Holders	**$5,135,136**	$7,264,048
Trust Corpus – 46,608,796 Units of Beneficial Interest Authorized and Outstanding	**1,439,214**	1,610,630
	$6,574,350	$8,874,678

STATEMENTS OF DISTRIBUTABLE INCOME
FOR THE THREE YEARS ENDED DECEMBER 31, 2006

	2006	2005	2004
Royalty Income (Notes 2 and 3)	**$66,407,199**	$62,967,150	$45,016,670
Interest Income	**133,648**	63,909	19,883
	66,540,847	63,031,059	45,036,553
Expenditures – General and Administrative	**825,478**	763,390	489,810
Distributable Income	**$65,715,369**	$62,267,669	$44,546,743
Distributable Income per Unit (46,608,796 Units)	**$ 1.410082**	$ 1.335964	$ .955758

STATEMENTS OF CHANGES IN TRUST CORPUS
FOR THE THREE YEARS ENDED DECEMBER 31, 2006

	2006	2005	2004
Trust Corpus, Beginning of Period	**$ 1,610,630**	$ 1,795,267	$ 1,991,594
Amortization of Net Overriding Royalty Interests (Notes 2 and 3)	**(171,416)**	(184,637)	(196,327)
Distributable Income	**65,715,369**	62,267,669	44,546,743
Distributions Declared	**(65,715,369)**	(62,267,669)	(44,546,743)
Trust Corpus, End of Period	**$ 1,439,214**	$ 1,610,630	$ 1,795,267

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

NOTES TO FINANCIAL STATEMENTS

1. Trust Organization and Provisions

The Permian Basin Royalty Trust ("Trust") was established as of November 1, 1980. Bank of America, N.A. ("Trustee") is Trustee for the Trust. Southland Royalty Company ("Southland") conveyed to the Trust (1) a 75% net overriding royalty in Southland's fee mineral interest in the Waddell Ranch in Crane County, Texas ("Waddell Ranch properties") and (2) a 95% net overriding royalty carved out of Southland's major producing royalty properties in Texas ("Texas Royalty properties"). 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 shareholders of record as of November 3, 1980, who received one Unit in the Trust for each share of Southland common stock held. The Units are traded on the New York Stock Exchange.

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's historical net book value at the date of the transfer to the Trust. Accumulated amortization as of December 31, 2006 and 2005, aggregated $9,536,002 and $9,364,586, respectively.

3. Basis of Accounting

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

- Royalty income recorded is the amount computed and paid by the working interest owner to the Trustee on behalf of the Trust.
- Trust expenses 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.

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.

4. New Accounting Pronouncements

In February 2006, the FASB issued SFAS No. 155, Accounting for Certain Hybrid Financial Instruments – an amendment of FASB Statements No. 133 Accounting for Derivative Instruments and No. 140 Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities. This statement resolves issues addressed in Statement 133 Implementation Issue No. D1, Application of Statement 133 to Beneficial interests in Securitized Financial Assets. This statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. The Trust has no such financial instruments and accordingly, this new Standard will not impact the financial statements of the Trust.

In March 2006, the FASB issued SFAS No. 156, Accounting for Servicing of Financial Assets – an amendment of FASB Statements No. 140 Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities. This statement requires an entity to recognize a servicing asset or servicing liability each time it undertakes an obligation to service a financial asset by entering into

NOTES TO FINANCIAL STATEMENTS

a servicing contract in certain situations. This statement is effective as of the beginning of an entity's first fiscal year that begins after September 15, 2006. The Trustee does not believe the adoption of this statement will have a material effect on the Trust's financial statements.

In July 2006, the FASB issued FASB Interpretation No. 48 ("FIN 48"), "Accounting for Uncertainty in Income Taxes," which clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." FIN 48 is effective for fiscal years beginning after December 15, 2006. The Trustee does not believe that the adoption of this statement will have a material effect on the Trust's financial statements.

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106 and 132(R)*. This statement improves financial reporting by requiring an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity or changes in unrestricted net assets of a not-for-profit organization. This statement is effective as of the end of the fiscal year ending after December 15, 2006. The Trustee does not believe that the adoption of this statement will have a material effect on the Trust's financial statements.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Trustee does not believe that the adoption of this statement will have a material effect on the Trust's financial statements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115*. This statement permits entities to choose to measure many financial instruments and certain other items at fair value. This statement is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. The Trustee does not believe that the adoption of this statement will have a material effect on the Trust's financial statements.

In September 2006, the FASB issued SAB No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in the Current Year Financial Statements*, for the purpose of evaluating materiality. This statement is effective for annual financial statements covering the first fiscal year ending after November 15, 2006. The Trustee does not believe that the adoption of this standard will have a material effect on the Trust's financial statements.

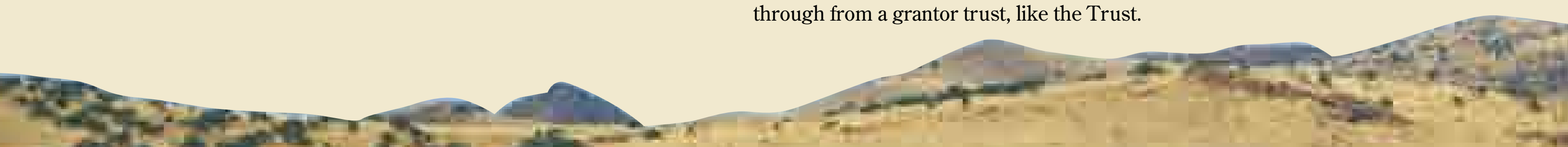
5. Federal Income Tax

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.

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 coal seam gas produced from the Underlying Properties. During 2006, 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). If any portion of the Royalties is treated as a production payment or is not treated as an economic interest, however, a Unit holder will not be entitled to depletion in respect of such portion. 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 Code, the taxpayer generally must recapture the amount deducted for depletion in 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 United States Treasury regulations govern dispositions of property after March 13, 1995. The Service will likely 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 deduct "miscellaneous itemized deductions" (including, in general, investment expenses) only to the extent that such expenses exceed 2 percent of the individual's adjusted gross income. Although there are exceptions to the 2 percent limitation, authority suggests that no exceptions apply to expenses passed through from a grantor trust, like the Trust.



NOTES TO FINANCIAL STATEMENTS

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.

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. Significant Customers

Information as to significant purchasers of oil and gas production attributable to the Trust's economic interests is included in Item 2 of the Trust's Annual Report on Form 10-K which is included in this report.

7. Proved Oil and Gas Reserves (Unaudited)

Proved oil and gas reserve information is included in Item 2 of the Trust's Annual Report on Form 10-K which is included in this report.

8. 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, 2006 (in thousands, except per Unit amounts):

	Royalty Income	Distributable Income	Distributable Income and Distribution Per Unit
2006			
First Quarter	**$18,918**	$18,653	$ .400354
Second Quarter	**14,041**	13,844	.297034
Third Quarter	**18,697**	18,576	.398559
Fourth Quarter	**14,751**	14,642	.314135
Total	**$66,407**	$65,715	$1.410082
2005			
First Quarter	**$13,531**	$13,244	$ .284149
Second Quarter	**12,746**	12,521	.268627
Third Quarter	**15,989**	15,890	.340939
Fourth Quarter	**20,701**	20,613	.442249
Total	**$62,697**	$62,268	$1.335964

9. Subsequent Events

Subsequent to December 31, 2006, the Trust declared the following distributions:

Monthly Record Date	Payment Date	Distribution Per Unit
January 31, 2007	February 14, 2007	$.101215
February 28, 2007	March 14, 2007	$.090695

10. State Tax Considerations

All revenues from the Trust are from sources within Texas, which has no individual income tax. However, the franchise tax imposed through December 31, 2006 by the state of Texas on corporations (the definition of which generally includes limited liability companies) is partly based on federal taxable income, which will include income from the Trust.

The Texas legislature recently passed H.B. 3, 79th Leg., 3d C.S. (2006), which was signed into law on May 18, 2006. H.B. 3 significantly reforms the Texas franchise tax system and replaces it with a new Texas margin tax system. The margin tax expands the type of entities subject to tax to generally include all active business entities, including corporations and limited liability companies currently subject to the franchise tax. The new margin tax also will apply to the following common entity types that are not currently subject to tax: general and limited partnerships (unless otherwise exempt), limited liability partnerships, trusts (unless otherwise exempt), business trusts, business associations, professional associations, joint stock companies, holding companies, and joint ventures. The effective date of the margin tax is January 1, 2008, but the tax generally will be imposed on gross revenues generated in 2007 and thereafter (earlier for certain fiscal year taxpayers).

If the Trust is exempt from the margin tax at the Trust level as a passive entity, each Unit holder that is a business entity subject to the margin tax would generally include its share of the Trust's revenues in its margin tax computation. If, however, the margin tax is imposed on the Trust at the Trust level, each such Unit holder would generally exclude its share of the Trust's revenues from its margin tax calculation.

Trusts and partnerships that meet statutory requirements and receive at least 90% of their gross income from designated sources, including royalties from mineral properties, are generally exempt from the margin tax as "passive entities." Virtually all of the income of the Trust consists of income from net overriding royalty interests (or net profits interests) that are treated as royalty income for federal income tax purposes. Although the income of the Trust is passive as it consists almost entirely of royalty and other non-operating mineral interests, there is currently no clear authority that the Trust satisfies all the statutory requirements for the exemption for passive entities to apply. Therefore, pending additional legislative action in the 2007 legislative session or the issuance of applicable administrative rules promulgated by the Texas Comptroller, it is uncertain whether the Trust would be exempt from the margin tax as a passive entity or subject to the margin tax at the Trust level.

Each Unit holder that is a business entity should consult his own tax advisor regarding the requirements for filing Texas, franchise and margin tax returns.

RESULTS OF THE FOURTH QUARTERS OF 2006 AND 2005

Royalty income received by the Trust for the fourth quarter of 2006 amounted to $14,751,459 or $.316495 per Unit. For the fourth quarter of 2005, the Trust received royalty income of $20,700,741 or $.444138 per Unit. Interest income for the fourth quarter of 2006 amounted to $38,297 compared to $27,098 for the fourth quarter of 2005. The increase in interest income can be attributed primarily to an increase in interest rate. General and administrative expenses totaled $148,089 for the fourth quarter of 2006 compared to $115,154 for the fourth quarter of 2005.

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 2005 are as follows:

Fourth Quarter	2006	2005
Royalties		
Oil Sales (Bbls)	**175,356**	222,071
Gas Sales (Mcf)	**734,754**	991,092
Underlying Properties		
Total Oil Sales (Bbls)	**308,453**	309,862
Average Per Day (Bbls)	**3,353**	3,368
Average Price/Bbls	**$ 59.14**	$ 58.88
Total Gas Sales (Mcf)	**1,578,248**	1,499,863
Average Per Day (Mcf)	**17,155**	16,303
Average Price/Mcf	**$ 6.83**	$ 8.70

The posted price of oil increased for the fourth quarter of 2006 compared to the fourth quarter of 2005, resulting in an average price per barrel of $59.14 compared to $58.88 in the same period of 2005. The average price of gas decreased for the fourth quarter of 2006 compared to the same period in 2005, resulting in an average price per Mcf of $6.83 compared to $8.70 in the fourth quarter of 2005.

The Trustee has been advised that oil sales decreased in 2006 compared to the same period in 2005 primarily due to natural production declines. Gas sales from the Underlying Properties decreased in the fourth quarter of 2006 compared to the same period in 2005 due to the same factor.

The Trust has been advised that 8 wells were drilled and completed during the three months ended December 31, 2006, and there were 3 wells in progress.

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

	Payments Due by Period				
Contractual Obligations	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Distribution payable to Unit holders	$5,135,136	$5,135,136	0	0	0
Total	$5,135,136	$5,135,136	0	0	0

INDEPENDENT AUDITORS' REPORT

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, 2006 and 2005, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2006. 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 consolidated financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of the Trust at December 31, 2006 and 2005, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2006, 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 effectiveness of the Trust's internal control over financial reporting as of December 31, 2006, 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 13, 2007 expressed an unqualified opinion on the Trustee's assessment of the effectiveness of the Trust's internal control over financial reporting.

Deloitte & Touche LLP
Dallas, Texas
March 13, 2007

Form 10-K

2006

PERMIAN BASIN ROYALTY TRUST

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2006

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.)*

Bank of America, N.A.
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 ☑ No ☐

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☑ Non-accelerated filer ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter was $571,465,450.

At March 1, 2007, there were 46,608,796 Units of Beneficial Interest of the Trust outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

"Units of Beneficial Interest" at page 1; "Trustee's Discussion and Analysis for the Three-Year Period Ended December 31, 2006" at pages 8 through 10; "Results of the 4th Quarters of 2006 and 2005" at page 11; and "Statements of Assets, Liabilities and Trust Corpus," "Statements of Distributable Income," "Statements of Changes in Trust Corpus," "Notes to Financial Statements" and "Report of Independent Registered Public Accounting Firm" at page 13 et seq., in registrant's Annual Report to security holders for fiscal year ended December 31, 2006 are incorporated herein by reference for Item 5, Item 7 and Item 8 of Part II of this Report.

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 convey the uncertainty of future events or outcomes.

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PART I

Item 1. *Business*

The Permian Basin Royalty Trust (the "Trust") is an express trust created under the laws of the state of Texas by the Permian Basin Royalty Trust Indenture (the "Trust Indenture") entered into on November 3, 1980, between Southland Royalty Company ("Southland Royalty") and The First National Bank of Fort Worth, as Trustee. Bank of America, N.A., 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. 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 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. ("MOI"), which was the parent company of Southland Royalty, became a wholly owned direct subsidiary of BRI. In 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. In 1996, MOI changed its name to Burlington Resources Oil & Gas Company, now Burlington Oil & Gas Company LP ("BROG"). 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. We shall post these reports as soon as reasonably practicable after we electronically file them with, or furnish them to the SEC.

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 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 2007 net proceeds could increase compared to the electrical costs incurred during 2006 principally as a result of higher fuel surcharges which could be charged by the third party electricity provider in response to the higher costs of natural gas consumed to generate the electricity. These increased costs could reduce the Trust share of 2007 net proceeds below the level that would exist if such costs remained at the level experienced in 2006. If production and development costs attributable to the Royalties exceed the gross proceeds related to production from the Underlying Properties, the Trust will not receive net proceeds until future proceeds from production exceed the total of the excess costs plus accrued interest during the deficit period. Development activities may not generate sufficient additional proceeds to repay the costs.

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

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

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

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

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

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.

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' 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, the war in Iraq and other sustained military campaigns could adversely affect Trust distributions or the market price of the Units in unpredictable ways, including through the disruption of fuel supplies and markets, increased volatility in crude oil and natural gas prices, or the possibility that the infrastructure on which the operators developing the Underlying Properties rely could be a direct target or an indirect casualty of an act of terror.

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

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

The 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, 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.

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.

If it is determined that the Trust is subject to the Texas margin tax, the Trustee may have to withhold a disproportionate amount from future distributions to pay the tax liability.

The Trustee does not intend to pay any amounts for the new Texas margin tax for tax year 2007, based on the assumption that the Trust is exempt from tax as a passive entity; however, there is currently no clear statutory authority that the Trust meets requirements for the margin tax exemption as a passive entity. If it is subsequently determined that the Trust is not exempt from the margin tax, the Trust would be required to deduct and withhold from future distributions the amounts necessary to pay the margin tax for the entire 2007 year, including the tax liability accruing on income distributed after December 2006 attributable to 2007 Trust revenues from which no tax was withheld. For more information about the margin tax, see Note 9 to the Trust's financial statements contained in the Trust's Annual Report to security holders.

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 within the 180 days preceding December 31, 2006, 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 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.

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

PRODUCING ACREAGE, WELLS AND DRILLING

Waddell Ranch Properties. The Waddell Ranch properties consist of 76,922 gross (33,246 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, 2006, the Waddell Ranch properties contained 800 gross (353 (net) productive oil wells, 205 gross (97 net)] productive gas wells and 309 gross (134 net) injection wells.

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

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 23 gross (11 net) wells drilled and completed on the Waddell Ranch properties during 2006. At December 31, 2006, there were 3 drill wells and 6 workovers in progress on the Waddell Ranch properties. There were 6 gross (3 net) wells drilled and completed on the Waddell Ranch properties during 2005. At December 31, 2005 there were no wells in progress on the Waddell Ranch properties. There were 4 gross (2 net) wells drilled and completed on the Waddell Ranch properties during 2004. At December 31, 2004 there were no wells in progress on the Waddell Ranch properties.

BROG has advised the Trustee that the total amount of capital expenditures for 2006 with regard to the Waddell Ranch properties totaled $35.6 million. Capital expenditures include the cost of remedial and maintenance activities. This amount spent is approximately $12.3 million more than the budgeted amount projected by BROG for 2006. BROG has advised the Trustee that the capital expenditures budget for 2007 totals approximately $32.4 million, of which approximately $18.9 million (gross) is attributable to the 2007 drilling program, and $12.4 million (gross) to workovers and recompletions. Accordingly, there is a 9.0% decrease in capital expenditures for 2007 as compared with the 2006 capital expenditures. The major reason for the variance is the decrease in the number of planned capital drill wells. There will be 20 new drill wells in 2007 as compared to 26 in 2006.

Texas Royalty Properties. The Texas Royalty properties consist of royalty interests in mature producing oil fields, such as Yates, Wasson, Sand Hills, East Texas, Kelly-Snyder, Panhandle Regular, N. Cowden, Todd, Keystone, Kermit, McElroy, Howard-Glasscock, Seminole and others. The Texas Royalty properties contain approximately 303,000 gross (approximately 51,000 net) producing acres. 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 Corporation (“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 at 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 being transferred from STC to Riverhill Energy. STC currently conducts all field, technical and accounting operations, on behalf of BROG, with regard to the Waddell Ranch properties. STC currently provides summary reporting of monthly results for both the Texas Royalty properties and the Waddell Ranch properties.

Well Count and Acreage Summary. The following table shows as of December 31, 2006, the gross and net producing wells and acres for the BROG and Riverhill Energy interests. The net wells and acres are determined by multiplying the gross wells or acres by the BROG and Riverhill Energy interests owner’s working interest in the wells or acres. There is very little undeveloped acreage held by the Trust, and all this is held by production.

	Number of Wells		Acres	
	Gross	**Net**	**Gross**	**Net**
BROG and Riverhill Energy Interests	1,313	589	76,922	33,246

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 and the related average sales prices attributable to the Underlying Properties for the three years ended December 31, 2006, excluding portions attributable to the adjustments discussed below, were as follows:

	Waddell Ranch Properties			Texas Royalty Properties			Total		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
Royalties:									
Production									
Oil (barrels)	429,052	501,499	471,441	320,897	325,776	307,611	749,949	827,275	779,052
Gas (Mcf)	2,640,873	3,052,103	2,642,599	513,918	556,675	602,518	3,154,791	3,608,778	3,245,117
Underlying Properties:									
Production									
Oil (barrels)	863,198	899,197	873,466	357,967	359,387	349,113	1,221,165	1,258,584	1,222,579
Gas (Mcf)	5,396,777	5,517,845	5,291,295	576,411	614,871	684,572	5,973,188	6,132,716	5,975,867
Average Price									
Oil/barrel	59.15	$ 49.35	$ 37.13	59.50	$ 48.97	$ 34.89	59.30	$ 49.20	$ 36.25
Gas/Mcf	7.63	$ 6.90	$ 5.47	10.02	$ 8.22	$ 5.79	8.02	$ 7.11	$ 5.53

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 2006 was $28 million (gross) and $25 million (net). The lease operating expense increased 3% from 2005 to 2006 primarily because of an increase in electrical costs. Waddell Ranch lifting cost on a barrel of oil equivalent (BOE) basis was $6.95/bbl as compared to $6.05 in 2005 and $5.32 in 2004.

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 for the period August 1, 1993 through February 28, 2007, the oil from the Ranch properties was and will be sold under a competitive bid to independent third parties.

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

OIL AND GAS RESERVES

The following are definitions adopted by the Securities and Exchange Commission ("SEC") and the Financial Accounting Standards Board which are applicable to terms used within this Item:

> *"Proved reserves"* are those estimated quantities of crude oil, natural gas and natural gas liquids, which, upon analysis of geological and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions.
>
> *"Proved developed reserves"* are those proved reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved undeveloped reserves" are those proved reserves which are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.

"Estimated future net revenues" are computed by applying current prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements and allowed by federal regulation) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, and assuming continuation of existing economic conditions.

"Estimated future net revenues" are sometimes referred to herein as "estimated future net cash flows."

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

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. The following table presents a reconciliation of proved reserve quantities from January 1, 2004 through December 31, 2006 (in thousands):

	Waddell Ranch Properties		Texas Royalty Properties		Total	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
January 1, 2004	3,531	21,822	3,376	5,425	6,907	27,247
Extensions, discoveries, and other additions	0	0	0	0	0	0
Revisions of previous estimates	546	2,692	434	1,091	980	3,783
Production	(471)	(2,643)	(308)	(602)	(779)	(3,245)
December 31, 2004	3,606	21,871	3,502	5,914	7,108	27,785
Extensions, discoveries, and other additions	84	415	0	0	84	415
Revisions of previous estimates	126	1,695	359	246	485	1,941
Production	(501)	(3,052)	(326)	(557)	(827)	(3,609)
December 31, 2005	3,315	20,929	3,535	5,603	6,850	26,532
Extensions, discoveries, and other additions	33	490	0	2	33	492
Revisions of previous estimates	233	208	212	53	445	261
Production	(429)	(2,641)	(321)	(514)	(750)	(3,155)
December 31, 2006	3,152	18,986	3,426	5,144	6,578	24,130

Estimated quantities of proved developed reserves of crude oil and natural gas as of December 31, 2006, 2005 and 2004 were as follows (in thousands):

	Crude Oil (Bbls)	Natural Gas (Mcf)
December 31, 2006	6,443	23,233
December 31, 2005	6,764	25,877
December 31, 2004	6,988	27,545

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 year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves. 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 2006, 2005 and 2004 change in the standardized measure of discounted future net cash revenues related to future royalty income from proved reserves attributable to the Royalties discounted at 10% is as follows (in thousands):

	Waddell Ranch Properties			Texas Royalty Properties			Total		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
January 1	$188,697	$156,014	$117,755	$104,654	$ 81,179	$ 57,796	$293,351	$237,193	$175,551
Extensions, discoveries, and other additions	2,108	3,743	0	15	0	0	2,123	3,743	0
Accretion of discount	18,870	15,601	11,776	10,465	8,118	5,780	29,335	23,719	17,556
Revisions of previous estimates and other	(3,224)	56,830	57,820	10,793	34,833	31,283	7,569	91,663	89,103
Royalty income	(43,143)	(43,491)	(31,337)	(23,264)	(19,476)	(13,680)	(66,407)	(62,967)	(45,017)
December 31	$163,308	$188,697	$156,014	$102,663	$104,654	$ 81,179	$265,971	$293,351	$237,193

Oil and gas prices of $53.44 and $53.47 per barrel and $5.37 and $7.69 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, 2006. The downward revisions of both reserves and discounted future net cash flows for the Waddell Ranch properties and the Texas Royalty properties are primarily due to decrease in oil and gas prices from 2005 to 2006.

Oil and gas prices of $54.89 and $54.02 per barrel and $6.38 and $7.06 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, 2005. The upward revisions of both reserves and discounted future net cash flows for the Waddell Ranch properties and the Texas Royalty properties were mostly due to increase in oil and gas prices from 2004 to 2005.

Oil and gas prices of $37.90 and $39.07 per barrel and $6.22 and $6.61 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, 2004. 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 increases in oil and gas prices from 2003 to 2004.

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, 2006, 2005 and 2004 (in thousands except amounts per Unit):

	2006		2005		2004	
	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	$255,703	$163,308	$298,417	$188,697	$257,563	$156,014
Texas Royalty properties	$212,486	$102,663	$219,657	$104,654	$167,402	$ 81,179
Total	$468,189	$265,971	$518,074	$293,351	$424,965	$237,193

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 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 FERC. On August 8, 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, to direct 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 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 and FERC final decisions.

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 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).

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.

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, environmental protection, occupational safety, resource conservation and equal employment opportunity. The Trustee does not believe that compliance with these laws by the operating parties will have any material adverse effect on Unit holders.

Item 3. *Legal Proceedings*

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

Item 4. *Submission of Matters to a Vote of Security Holders*

No matters were submitted to a vote of Unit holders, through the solicitation of proxies or otherwise, during the fourth quarter ended December 31, 2006.

PART II

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

The information under "Units of Beneficial Interest" at page 1 of the Trust's Annual Report to security holders for the year ended December 31, 2006, is herein incorporated by reference.

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,				
	2006	2005	2004	2003	2002
Royalty income	$66,407,199	$62,967,150	$45,016,670	$32,596,078	$23,830,604
Distributable income	$65,715,369	$62,267,669	44,546,743	32,113,125	23,415,406
Distributable income per Unit	$ 1.410082	1.335964	.955758	0.688993	0.502382
Distributions per Unit	$ 1.410082	1.335964	.955758	0.688993	0.502382
Total assets, December 31	$ 6,574,350	$ 8,874,678	$ 7,224,412	$ 4,865,569	$ 4,543,780

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operation*

The "Trustee's Discussion and Analysis for the Three Year Period Ended December 31, 2006" and "Results of the 4th Quarters of 2006 and 2005" at pages 7 et seq. of the Trust's Annual Report to security holders for the year ended December 31, 2006 is herein incorporated by reference.

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.

Item 8. *Financial Statements and Supplementary Data*

The Financial Statements of the Trust and the notes thereto at page 13 et seq. of the Trust's Annual Report to security holders for the year ended December 31, 2006, are herein incorporated by reference.

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

There have been no changes in accountants and no disagreements with accountants on any matter of accounting principles or practices or financial statement disclosures during the twenty-four months ended December 31, 2006.

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 and Exchange Act of 1934, as amended. Based upon that evaluation, the Trustee concluded that the Trust's disclosure controls and procedures are effective in timely alerting the Trustee to material information relating to the Trust required to be included in the Trust's periodic filings with the Securities and Exchange Commission. 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 2006 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, 2006. The Trustee's assessment of the effectiveness of the Trust's internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report which is included herein.

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 Trustee's assessment, included in the accompanying Trustee's report on internal control over financial reporting that Permian Basin Royalty Trust (the "Trust") maintained effective internal control over financial reporting as of December 31, 2006, 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 — modified cash basis ("internal control over financial reporting") and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on the Trustee's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

The 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. The 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 Trustee's assessment that the Trust maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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 Permian Basin Royalty Trust (the "Trust") as of December 31, 2006 and 2005, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2006, 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 13, 2007 expressed an unqualified opinion on those financial statements.

DELOITTE & TOUCHE LLP

Dallas, Texas
March 13, 2007

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 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 2006, 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), with the exception that BROG failed to timely make a filing related to a sale of units of the Trust.

CODE OF ETHICS

Because the Trust has no employees, it does not have a code of ethics. Employees of the Trustee, Bank of America, N.A., 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 Bank of America, N.A., Trustee, P.O. Box 830650, Dallas, Texas 75202, Attention: Ron Hooper.

Item 11. ***Executive Compensation***

During the years ended December 31, 2006, 2005 and 2004, the Trustee received total remuneration as follows:

Name of Individual or Number of Persons in Group	Cash Compensation	Year
Bank of America, N.A.	$67,395(1)	2006
	$78,294(1)	2005
	$46,693(1)	2004

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

COMPENSATION COMMITTEE

Because the Trust has no directors, it does not have a compensation committee.

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

(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 1, 2007.

(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 1, 2007, an aggregate of 172,310 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*

The Trust has no directors or executive officers. See Item 11 for the remuneration received by the Trustee during the years ended December 31, 2006, 2005 and 2004 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, 2006 and 2005 are:

	2006	2005
Audit Fees	$132,100	$132,850
Audit-related fees	19,250	—
Tax fees	—	—
All other fees	—	—
Total	$151,350	$132,850

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.

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 by reference to the Annual Report of the Trust for the year ended December 31, 2006:

Report of Independent Registered Public Accounting Firm

Statements of Assets, Liabilities and Trust Corpus at December 31, 2006 and 2005

Statements of Distributable Income for Each of the Three Years in the Period Ended December 31, 2006

Statements of Changes in Trust Corpus for Each of the Three Years in the Period Ended December 31, 2006

Notes to Financial Statements

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.*
(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.*
(13)	—	Registrant's Annual Report to security holders for fiscal year ended December 31, 2006.**
(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.**

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

** Filed herewith.

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.

PERMIAN BASIN ROYALTY TRUST

By: BANK OF AMERICA, N.A., Trustee

By: /s/ Ron E. Hooper
Ron E. Hooper
Senior Vice President

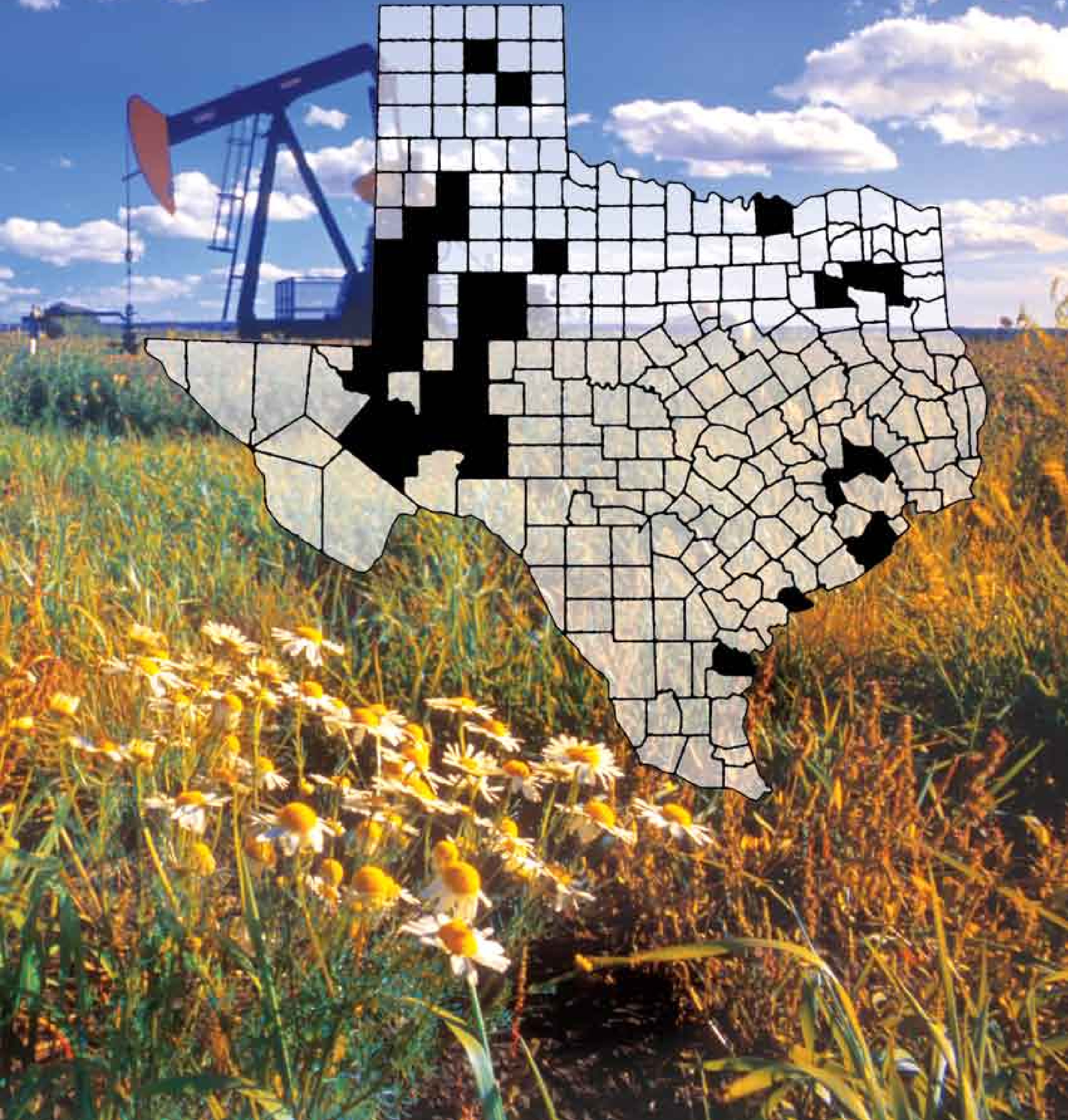
Date: March 13, 2007

(The Trust has no directors or executive officers.)

TEXAS ROYALTY PROPERTIES ARE LOCATED IN 33 TEXAS COUNTIES.

Andrews	Crockett	Grayson	Hutchinson	Pecos	Upshur	Winkler
Borden	Ector	Gregg	Lubbock	Reagan	Upton	Wood
Brazoria	Gaines	Hale	Mitchell	Scurry	Van Zandt	Yoakum
Calhoun	Glasscock	Hockley	Montgomery	Stonewall	Waller	
Crane	Gray	Howard	Nueces	Terry	Ward	

Waddell Ranch properties are located in Crane County.



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TAX COUNSEL
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TRANSFER AGENT
Mellon Investor Services LLC
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