SJT

San Juan Basin Royalty Trust

Annual Report & Form 10K 2002

The Trust

The principal asset of the San Juan Basin Royalty Trust (the "Trust") consists of a 75% net overriding royalty interest carved out of certain oil and gas leasehold and royalty interests (the "Underlying Interests") in properties located in the San Juan Basin of northwestern New Mexico.

Units of Beneficial Interest

The units of beneficial interest of the Trust ("Units") are traded on the New York Stock Exchange under the symbol "SJT." At March 24, 2003, the latest practicable date, the sale price of a Unit was $14.70. From January 1, 2001, to December 31, 2002, quarterly high and low closing sales prices and the aggregate amount of monthly distributions per Unit paid each quarter were as follows:

2002	*High*	*Low*	*Distributions Paid*
First Quarter	*$11.9000*	*$ 9.2500*	*$ .075673*
Second Quarter	*12.2300*	*10.4900*	*.193414*
Third Quarter	*11.8800*	*9.7000*	*.263820*
Fourth Quarter	*13.9000*	*11.7000*	*.248447*
Total for 2002			*$ .781354*
2001			
First Quarter	*$16.1300*	*$12.3125*	*$ .799474*
Second Quarter	*17.9800*	*12.4000*	*.563215*
Third Quarter	*14.0000*	*10.0800*	*.294257*
Fourth Quarter	*11.5100*	*9.3000*	*.062177*
Total for 2002			*$ 1.719123*

At March 14, 2003, 46,608,796 Units outstanding were held by 1,972 Unit holders of record. The following table presents information relating to the distribution of ownership Units:

Type of Unit Holders	*Number of Unit Holders*	*Units Held*
Individuals, Individual Retirement Accounts, Joint Holders and Minors	*1,735*	*2,150,801*
Fiduciaries	*187*	*528,484*
Associations or Societies	*8*	*89,335*
Banks	*5*	*13,560*
Brokers, Dealers and Nominees	*1*	*43,498,794*
Corporations and Partnerships	*30*	*326,833*
Government Bodies	*6*	*989*
Total	*1,972*	*46,608,796*

To Unit Holders

We are pleased to present the 2002 Annual Report of the San Juan Basin Royalty 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, 2002, without exhibits. The Form 10-K contains important information concerning the Underlying Interests, defined below, including the oil and gas reserves attributable to the net overriding royalty interest owned by the Trust (the "Royalty"). Production figures provided in this letter and in the Trustee's Discussion and Analysis are based on information provided by Burlington Resources Oil & Gas Company LP ("BROG"). ■ The Trust was established in November 1980 by Southland Royalty Company ("Southland Royalty"). Pursuant to the Indenture that governs the operations of the Trust, Southland Royalty conveyed to the Trust a 75% net overriding royalty interest (equivalent to a net profits interest) carved out of Southland's oil and gas leasehold and royalty interests in properties in the San Juan Basin of northwestern New Mexico. The Royalty is the principal asset of the Trust. ■ Under the Trust Indenture, TexasBank (successor trustee) as Trustee, has the primary function of collecting monthly net proceeds ("Royalty Income") attributable to the Royalty and making the monthly distributions to the Unit holders after deducting administrative expenses and any amounts necessary for cash reserves. ■ Income distributed to Unit holders from February through December 2002 was $36,417,967 or $0.781354 per Unit. Distributable income for 11 months of 2002 consisted of Royalty Income of $38,053,281 plus interest income of $16,112, less administrative expenses of $1,728,187, plus a reduction in cash reserves of $76,761. The Trustee did not receive royalty income for January 2002 because revenues based on production during the month of November 2001 were less than expenses. Interest income of $150 received in January was added to cash reserves. ■ On January 2, 1996, Southland Royalty was merged with and became a wholly owned subsidiary of Meridian Oil, Inc. Subsequent to the merger, Meridian changed its name to Burlington Resources Oil & Gas Company LP. ■ Information about the Trust's estimated proved reserves of gas, including coal seam gas, and of oil as well as the present value of net revenues discounted at 10% can be found in Item 2 of the accompanying Form 10-K. ■ Certain Royalty Income is generally considered portfolio income under the passive loss rules enacted by the Tax Reform Act of 1986. Therefore, 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, 2003, and for the year ending December 31, 2003. Unit holders owning Units in nominee name may obtain monthly tax information from the Trustee upon request. ■ For readers' convenience, a glossary, which contains definitions, can be found on the inside back cover. Please visit our Web site at www.sjbrt.com to access news releases, reports, SEC filings and tax information.

TexasBank, Trustee

By: L.A. Anderson

Lee Ann Anderson
Vice President and Trust Officer

True chileheads prove it by making the annual pilgrimage to Hatch, NM – the Chile Capital of the World – for its Labor Day Chile Festival. The normally placid village northwest of Los Cruces becomes a mecca for fans of the Land of Enchantment's famed green chiles, a staple of Southwestern cuisine. Whether fresh or roasted, Hatch chiles add an unmistakable kick to chile rellenos, green enchiladas and fiery salsas. Novice festival-goers are well-advised to pack antacids for the trip.

If you can't stand the heat, well, maybe you're not a real chile chomper. Fieriness is rated by Scoville Units, named for the pharmacist who first measured capsaicin, the chemical in peppers that translates to heat. From mild Poblanos to scorching Habaneros, Pequins or Thai peppers, there's a variety of Capsicum *for every taste. A rule of thumb: The smaller the chile, the hotter the bite. Mouth on fire? Try milk or ice cream – not water or soda – to douse the flames.*

Description Of The Properties

The principal asset of the Trust is a 75% net overriding royalty interest carved out of certain working, royalty and other interests owned by BROG (the "Underlying Interests") in properties located in the San Juan Basin, and more particularly in San Juan, Rio Arriba and Sandoval Counties of northwestern New Mexico (the "Underlying Properties"). The Underlying Properties contain 151,900 gross (119,000 net) producing acres and 3,738 gross (1,135 net) producing wells, including dual completions.

The Underlying Properties have historically produced gas primarily from conventional wells drilled to three major formations: the Pictured Cliffs, the Mesaverde and the Dakota, ranging in depth from 1,500 to 8,000 feet. The characteristics of these reservoirs result in the wells having very long productive lives. A production index for oil and gas properties is the number of years derived by dividing remaining reserves by current production. Based upon the reserve report prepared by the Trust's independent petroleum engineers as of December 31, 2002, the production index for the San Juan Basin properties is estimated to be approximately 9.47 years. The production index is subject to change from year to year based on reserve revisions and production levels. Among the factors considered by the Trust's engineers in estimating remaining reserves of natural gas is the current sales price for gas. As the sales price increases, the producer can justify expending higher lifting costs and therefore reasonably expect to recover more of the known reserves. Accordingly, as gas prices rise, the production index increases and *vice versa*.

In February 2002, BROG informed the Trust that the New Mexico Oil Conservation Division (the "OCD") had approved plans for 80-acre infill drilling of the Dakota formation in the San Juan Basin. In October 2002, the OCD approved a reduction from 320- to 160-acre spacing for those portions of the Fruitland Coal formation where wells typically produce less than two MMcf per day. The OCD has asked BROG and other interested parties to study over the next year whether the change in spacing requirements should be expanded to cover other portions of that reservoir.

The process of removing coal seam gas is often referred to as degasification or desorption. Millions of years ago, natural gas was generated in the process of coal formation and absorbed into the coal. Water later filled the natural fracture system. When the water is removed from the natural fracture system, reservoir pressure is lowered and the gas desorbs from the coal. The desorbed gas then flows through the fracture system and is produced at the well bore. The volume of formation water production typically declines with time and the gas production may increase for a period of time before starting to decline. In order to dispose of the formation water, surface facilities including pumping units are required, which results in the cost of a completed well being as much as $500,000. During 2002, these coal seam wells produced a total of approximately 11,133,332 MMBtu of gas from the Underlying Properties, which was sold at an average price of $2.07 per MMBtu.

Production from coal seam wells drilled prior to January 1, 1993, qualifies for federal income tax credits through 2002. Thus, under current law, coal seam gas production after December 31, 2002, will not qualify for the Section 29 credit. For 2001, the credit was approximately $1.08 per MMBtu. For 2002, the amount of the credit will be determined by the Treasury Department no later than April 1, 2003, and, based on historical trends, is expected to approximate (within a 2-3% range) the 2001 credit. During 2001, potential Section 29 tax credits of approximately $.117920 per Unit were generated for Unit holders from production from coal seam wells.

In February 2002, BROG announced an estimated capital budget for the Underlying Properties of $17.1 million. During the year the estimate was initially reduced to $12.4 million and ultimately increased to $19.0 million. BROG's capital plan for the Underlying Properties for 2002 estimated 397 projects, including the drilling of 54 new wells operated by BROG and 26 wells operated by third parties. In 2002, BROG actually participated in 339 projects, including 41 new wells operated by BROG and 12 wells operated by third parties. BROG reported that the swings in the budget estimates related in large part to whether and when BROG was successful in obtaining the necessary governmental and landowner approvals to drill on a well-by-well basis.

The aggregate capital expenditures reported by BROG in calculating distributable income for 2002 include approximately $10.1 million attributable to the capital budgets for prior years. This occurs because projects within a given year's budget may extend into subsequent years, with capital expenditures attributable to those projects used in calculating distributable income to the Trust in those subsequent years. Further, BROG's accounting period for capital expenditures runs through November 30 of each calendar year, such that capital expenditures incurred in December of each year are actually accounted for as part of the following year's capital expenditures. Also, for wells not operated by BROG, BROG's share of capital expenditures may not actually be paid by it until the year or years after those expenses were incurred by the operator. Capital expenditures of approximately $11.4 million for 2002 budgeted projects were used in calculating distributable income in calendar year 2002, and approximately

$3.6 million in capital expenditures was used in calculating distributions for the first three months of 2003. Therefore, an additional approximately $4.0 million in capital expenditures for 2002 projects remains to be spent.

During 2002, in calculating the net proceeds to the Trust, BROG deducted approximately $21.5 million of capital expenditures for projects, including drilling and completion of 98 gross (30.05 net) conventional wells, recompletion of 36 gross (14.44 net) conventional wells, 13 gross (2.21 net) miscellaneous capital projects, 1 gross (.82 net) restimulation, 1 gross (.05 net) payadd, 16 gross (5.42 net) coal seam wells, 11 gross (1.45 net) miscellaneous coal seam capital projects, 14 gross (5.77 net) coal seam recompletions, 5 gross (.98 net) coal seam recavitations, 3 gross (.01 net) coal seam restimulations and facilities maintenance. There were 61 gross (24.49 net) new conventional wells, 20 gross (4.69 net) conventional well recompletions, 65 gross (19.82 net) miscellaneous conventional capital projects, 4 gross (1.41 net) coal seam wells, 2 gross (.99 net) coal seam recompletions, and 5 gross (1.72 net) miscellaneous coal seam capital projects in progress as of December 31, 2002.

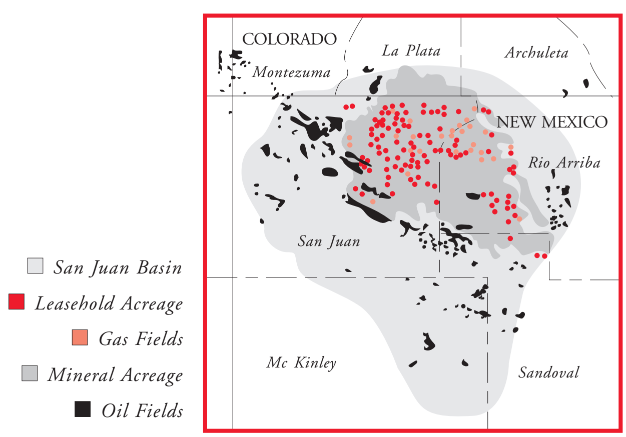
During 2001, in calculating the net proceeds to the Trust, BROG deducted approximately $33 million of capital expenditures for projects, including drilling and completion of 92 gross (36.33 net) conventional wells, recompletion of 33 gross (18.18 net) conventional wells, 13 gross (2.85) net miscellaneous capital projects, 3 gross (2.34 net) restimulations, 56 gross (8.40 net) conventional payadds, 10 gross (1.52 net) coal seam wells, 4 gross (1.61 net) coal seam recompletions, 1 gross (.88 net) coal seam payadd, 6 gross (.04 net) coal seam recavitations and facilities maintenance. There were 100 gross (32.47 net) new conventional wells, 31 gross (13.47 net) conventional well recompletions, 2 gross (.87 net) miscellaneous conventional capital projects, 9 gross (3.17 net) conventional payadds, 15 gross (1.09 net) conventional restimulations, 12 gross (5.36 net) coal seam wells, 7 gross (4.11 net) coal seam recompletions, 2 gross (.02 net) coal seam restimulations and 6 gross (.29 net) miscellaneous coal seam capital projects in progress as of December 31, 2001.

For 2003, BROG's announced plan for the Underlying Properties includes 351 projects at an aggregate cost of $14.1 million. Approximately $10.6 million of that budget is allocable to new wells, with approximately 41% of those wells projected to be drilled to formations producing coal seam gas as distinguished from conventional gas. BROG reports that based on its actual capital requirements, its mix of projects and swings in the price of natural gas, the actual capital expenditures for 2003 could range from $10 million to $22 million. In August 2002, the New Mexico Oil Conservation Division approved reduced, 160-acre spacing in selected portions of the Fruitland Coal formation. BROG has indicated that, principally as a result of that decision, its budget for 2003 reflects a focus on the Fruitland Coal formation.

BROG has previously informed the Trust that increases in its capital program, particularly in 2000 and 2001, were designed to offset the natural decline in production from the Underlying Properties. BROG has reported favorable results in this effort in that natural gas production for calendar year 2002 averaged approximately 127 MMcf per day, as compared to average production of approximately 121 MMcf per day for calendar 2001 and 116 MMcf per day for calendar 2000.

BROG indicates its budget for 2003 reflects continued significant development of properties in which the Trust's net overriding royalty interest is relatively high, sustained focus on conventional formations, including infill drilling to the Mesaverde and Dakota formations, development of the Fruitland Coal formation and multiple formation completions.

The Federal Energy Regulatory Commission is primarily responsible for federal regulation of natural gas. For a further discussion of gas pricing, gas purchasers, gas production and regulatory matters affecting gas production see Item 2, "Properties," in the accompanying Form 10-K.



Distributable Income consists of Royalty Income plus interest, less the general and administrative expenses of the Trust and any changes in cash reserves established by the Trustee. For the year ended December 31, 2002, Distributable Income decreased to $36,417,967 from $80,126,202 distributed in 2001. The decrease was primarily attributable to lower gas and oil prices and to the loss of the Val Verde Credit (as defined and described below), offset in part by the effect of audit exceptions identified by the Trust's joint interest auditors and granted and paid by BROG in the third quarter.

Interest income decreased from $165,676 in 2001 to $16,112 in 2002, primarily due to lower interest rates and decreased funds available to invest.

Total gas and oil production from the Underlying Properties for the five years ended December 31, 2002, were as follows:

	2002	*2001*	*2000*	*1999*	*1998*
Gas – Mcf	*46,206,297*	*42,960,149*	*42,220,260*	*39,940,175*	*41,507,353*
Mcf per Day	*126,593*	*117,699*	*115,356*	*109,425*	*113,719*
Oil-Bbls	*93,659*	*92,413*	*97,330*	*72,223*	*81,888*
Bbls per Day	*257*	*253*	*266*	*198*	*224*

Sales volumes attributable to the Royalty are determined by dividing the net profits received by the Trust and attributable to oil and gas, respectively, by the prices received for sales volumes from the Underlying Properties, taking into consideration production taxes attributable to the Underlying Properties. Since the oil and gas sales attributable to the Royalty are based on an allocation formula dependent on such factors as price and cost, including capital expenditures, the aggregate sales amounts from the Underlying Properties may not provide a meaningful comparison to sales attributable to the Royalty.

Royalty Income for the calendar year is associated with actual gas and oil production during the period from November of the preceding year through October of the current year. Gas and oil sales attributable to the Royalty for the past five years are summarized in the following table:

	2002	*2001*	*2000*	*1999*	*1998*
Gas – Mcf	*19,584,056*	*19,272,021*	*20,317,750*	*19,527,666*	*18,904,906*
Average Price (per Mcf)	*$2.32*	*$4.61*	*$2.99*	*$1.78*	*$1.75*
Oil – Bbls	*40,215*	*42,056*	*47,441*	*35,341*	*37,067*
Average Price (per Bbl)	*$20.90*	*$24.99*	*$24.66*	*$14.41*	*$13.55*

The fluctuations in annual gas production that have occurred during these five years generally resulted from changes in the demand for gas during that time, marketing conditions, and increased capital spending to generate production from new wells. Production from the Underlying Properties is influenced by the line pressure of the gas gathering systems in the San Juan Basin. As noted above, oil and gas sales attributable to the Royalty are based on an allocation formula dependent on many factors, including oil and gas prices and capital expenditures.

Royalty Income for the five years ended December 31, 2002, was determined as shown in the following table:

	2002	2001	2000	1999	1998
Gross Proceeds from the Underlying Properties:					
Gas	$103,349,299	$169,052,231	$124,902,689	$69,928,312	$71,247,501
Oil	1,863,827	2,233,071	2,409,158	1,028,862	1,088,228
Other	(5,110,589)[1]	-0-	4,653,333	1,189,996	-0-
Total	$100,102,537	$171,285,302	$131,965,180	$72,147,170	$72,335,729
Less Production Costs:					
Capital Costs	21,470,777	32,999,973	25,575,657	10,556,159	12,828,300
Severance Tax – Gas	9,752,508	16,687,074	12,059,286	7,180,973	7,341,098
Severance Tax – Oil	151,594	202,113	234,462	106,335	117,454
Other	18,037	55,000	129,161	(95,445)	66,892
Lease Operating Expenses	15,701,740	15,109,139	13,906,916	10,896,526	11,558,172
Total	47,094,656	65,053,299	51,905,482	28,644,548	31,911,916
Excess Production Costs	(2,259,628)	2,259,628	-0-	-0-	-0-
Interest on Excess Production Costs	(10,545)	-0-	-0-	-0-	-0-
Net Profits	50,737,708	108,491,631	80,059,698	43,502,622	40,423,813
Royalty Percentage	75%	75%	75%	75%	75%
Royalty Income	$ 38,053,281	$ 81,368,723	$ 60,044,773	$32,626,966	$30,317,860

(1) *Represents deductions by BROG from the net proceeds otherwise payable to the Trust in connection with the portion of various settlement agreements with the Mineral Management Service of the United States Department of Interior allocable to the Royalty (see Item 3 of Trust's Anuual Report on Form 10-K).*

Included in the 2000 distributable income was a payment by BROG to the Trust in June 2000 of $3,490,000. In June 2000, the Trust and BROG entered into a partial settlement of a claim relating to a gas imbalance. A gas imbalance occurs when more than one party is entitled to the economic benefit of the production of natural gas, but the gas is sold for the account of less than all the parties. Under the terms of the partial settlement, BROG paid the Trust $3,490,000 to settle the imbalance insofar as it relates to some of the wells located on the subject properties. BROG has indicated that the remainder of the imbalance is to be addressed through volume adjustments whereby the Trust's net overriding royalty interest will be applied to 50% of the overproduced parties' interest on a monthly basis, until the imbalance is corrected. The Trust is in communication with BROG in order to determine the estimated value of the volume adjustments and the time during which the remainder of the imbalance will be corrected.

Included in 1999 Distributable Income was a payment by BROG to the Trust in March 1999 of $892,498. After a rupture of the Williams "Trunk S" Pipeline disrupted a significant flow of gas from BROG properties, BROG filed claims with insurance carriers and subsequently received payments of its claims. Some of the claims filed related to properties burdened by the Royalty. The amount of insurance proceeds applicable to such properties was determined to be $1,189,996, of which the Trust received 75% or $892,498.

Based on its 1999 year-end review, BROG determined that it had undercharged the Trust for both capital expenditures and lease operating charges related to properties burdened by the Trust but not operated by BROG. In April and May of 2000, BROG passed through to the Trust additional charges of $652,303 in capital expenditures and $1,689,509 in lease operating charges related to the undercharged non-operated properties. The Trust's consultants have reviewed BROG's cost reporting data and confirmed that these additional charges were appropriate.

Operating expenses for 1998 through 2001 include the impact of the receipt of $250,000 from BROG as an offset to lease operating expense in connection with the settlement of the litigation described in Note 5 to the accompanying Financial Statements. The final $250,000 offset was made in December 2001. Monthly lease operating costs in 2002 averaged approximately $1,262,913, which is higher than the $1,242,247 average in 2001. For additional information on capital expenditures, see "Description of the Properties."

As part of the September 4, 1996, settlement of the litigation filed by the Trustee on June 4, 1992, against BROG and Southland Royalty Company, the Trust was entitled to certain adjustments (the "Val Verde Credit") that represented cost reductions favorable to the Trust in the charges for coal seam gas gathered and treated on BROG's Val Verde system. The settlement provided that the Val Verde Credit was applicable until the later of July 1, 2002, or until BROG no longer owned the Val Verde facility. By correspondence dated July 15, 2002, BROG notified the Trustee of the sale of the Val Verde facility to TEPPCO Partners, L.P. effective July 1, 2002. Accordingly, effective July 1, 2002, the calculation of net proceeds for gas gathered and treated at the Val Verde facility no longer included the Val Verde Credit. The total amount of the Val Verde Credit for the twelve months ended June 30, 2002, was estimated by the Trust's joint interest auditors as approximately $1,880,000. The loss of the Val Verde Credit will result in increased costs allocated to the Trust for coal seam gas gathered and treated on the Val Verde system and accordingly, will decrease Royalty Income.

The current war in Iraq has increased the volatility in prices for oil and gas. It is unclear what effect the current war in Iraq will have on the net proceeds received by the Trust and, accordingly, Distributable Income.

Contractual Obligations

Under the Trust's indenture, the Trustee is entitled to an administrative fee for its administrative services and the preparation of quarterly and annual statements of: (i) 1/20 of 1% of the first $100 million of the annual gross revenue of the Trust, and 1/30 of 1% of the annual gross revenue of the Trust in excess of $100 million and (ii) the Trustee's standard hourly rates for time in excess of 300 hours annually. Beginning January 1, 2003, in no case will the administrative fee due under items (i) and (ii) above be less than $36,000 per year (as adjusted annually to reflect the increase (if any) in the Producers Price Index as published by the U.S. Department of Labor, Bureau of Labor Statistics).

Effects Of Securities Regulation

As a publicly-traded trust listed on the New York Stock Exchange (the "NYSE"), the Trust is and will continue to be subject to extensive regulation under, among others, the Securities Act of 1933, the Exchange Act of 1934, the rules and regulations of the NYSE and the Sarbanes-Oxley Act of 2002. Issuers failing to comply with such authorities risk serious consequences, including criminal as well as civil and administrative penalties. In most instances, these laws, rules and regulations do not specifically address their applicability to publicly-traded trusts, such as the Trust. In particular, the Sarbanes-Oxley Act of 2002 provides for the adoption by the Securities and Exchange Commission (the "Commission") of certain rules and regulations that may be impossible for the Trust to literally satisfy because of its nature as a pass-through trust. For example, the Commission is required to adopt rules and regulations pursuant to the Sarbanes-Oxley Act of 2002 that would require a publicly-traded company's board of directors, audit committee or executive directors (or similar body) to act with respect to certain corporate governance matters. The Trust does not have, nor does the indenture governing the Trust provide for, a board of directors, an audit committee or any executive officers. Accordingly, the Trust could not literally comply with such rules and regulations. It is the Trustee's intention to follow the Commission's rulemaking closely, attempt to comply with such rules and regulations and, where appropriate, request relief from these rules and regulations. However, if the Trust is unable to comply with such rules and regulations or to obtain appropriate relief, the Trust may be required to expend as yet unknown but potentially material costs to amend the indenture that governs the Trust to allow for compliance with such rules and regulations.

Critical Accounting Policies

In accordance with the Commission's staff accounting bulletins and consistent with other royalty trusts, the financial statements of the Trust are prepared on the following basis:

- Royalty Income recorded for a month is the amount computed and paid by BROG to the Trustee for the Trust.
- Trust expenses recorded are based on liabilities paid and cash reserves established from Royalty Income for liabilities and contingencies.
- Distributions to Unit holders are recorded when declared by the Trustee.
- The conveyance which transferred the Royalty to the Trust provides that any excess of production costs over gross proceeds must be recovered from future net profits.

The financial statements of the Trust differ from financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") because revenues are not accrued in the month of production; certain cash reserves may be established for contingencies which would not be accrued in financial statements prepared in accordance with GAAP; and amortization of the Royalty calculated on a unit-of-production basis is charged directly to trust corpus instead of an expense.

Results Of The 4th Quarter Of 2002 And 2001

For the three months ended December 31, 2002, Distributable Income was $11,579,818 ($.248447 per Unit), which was more than the $2,898,013 ($.062177 per Unit) of income distributed during the same period in 2001. The increase in Distributable Income resulted primarily from higher average gas and oil prices, and decreased capital costs compared to the fourth quarter of 2001.

Royalty Income of the Trust for the fourth quarter is associated with actual gas and oil production during August through October of each year. Gas and oil sales for the quarters ended December 31, 2002 and 2001 were as follows:

Underlying Properties	*2002*	*2001*
Gas – Mcf	*11,608,135*	*10,248,195*
Average Price (per Mcf)	*$2.30*	*$1.87*
Oil – Bbls	*19,624*	*21,018*
Average Price (per Bbl)	*$23.61*	*$20.88*
Attributable to the Royalty		
Gas – Mcf	*5,574,600*	*1,483,888*
Oil – Bbls	*9,184*	*2,792*

The average price of gas and oil increased in the fourth quarter of 2002 compared to the same period in the prior year. The price per barrel of oil during the fourth quarter of 2002 was $2.73 per Bbl higher than that received in the fourth quarter of 2001 due to increases in oil prices in world markets generally, including the posted price applicable to the Royalty. Gas production increased slightly in the fourth quarter of 2002 as compared with the same period in 2001 primarily due to increased demand. During the fourth quarter of 2002, coal seam production from the Underlying Properties averaged 1,413,871 Mcf per month compared to 961,310 Mcf per month during the fourth quarter of 2001.

Capital costs for the fourth quarter of 2002 totaled $4,653,069 compared to $11,528,106 during the same period of 2001. The decrease was primarily due to decreased drilling activity in the fourth quarter of 2002 as compared to the same period in 2001. Lease operating expenses and property taxes for the fourth quarter of 2002 averaged $1,322,655 per month compared to $1,411,550 per month in the fourth quarter of 2001.

Statements of Assets, Liabilities and Trust Corpus
December 31, 2002 and 2001

Assets	2002	2001
Cash and Short-term Investments	$ 4,274,790	$ 191,620
Net Overriding Royalty Interests in Producing Oil and Gas Properties	33,697,906	37,859,749
	$37,972,696	$38,051,369
Liabilities and Trust Corpus		
Distribution Payable to Unit Holders	$ 4,159,932	$ -0-
Cash Reserves	114,858	191,620
Trust Corpus – 46,608,796 Units of Beneficial Interest Authorized and Outstanding	33,697,906	37,859,749
	$37,972,696	$38,051,369

Statements of Distributable Income
for the Three Years Ended December 31, 2002

	2002	2001	2000
Royalty Income	$38,053,281	$81,368,723	$60,044,773
Interest Income	16,112	165,676	148,513
	38,069,393	81,534,399	60,193,286
Expenditures – General and Administrative	1,728,187	1,216,577	1,004,354
Change in Cash Reserves	(76,761)	191,620	-0-
Distributable Income	$36,417,967	$80,126,202	$59,188,932
Distributable Income Per Unit (46,608,796 units)	$ 0.781354	$ 1.719123	$ 1.269909

Statements of Changes in Trust Corpus
for the Three Years Ended December 31, 2002

	2002	2001	2000
Trust Corpus, Beginning of Period	$37,859,749	$40,686,854	$45,186,199
Amortization of Net Overriding Royalty Interest	(4,161,843)	(2,827,105)	(4,499,345)
Distributable Income	36,417,967	80,126,202	59,188,932
Distribution Declared	(36,417,967)	(80,126,202)	(59,188,932)
Trust Corpus, End of Period	$33,697,906	$37,859,749	$40,686,854

The accompanying Notes to Financial Statements are an integral part of these statements.

1. Trust Organization And Provisions

The San Juan Basin Royalty Trust ("Trust") was established as of November 1, 1980. As of September 30, 2002, TexasBank ("Trustee") replaced Bank One, N.A., as Trustee for the Trust. Southland Royalty Company ("Southland") conveyed to the Trust a 75% net overriding royalty interest ("Royalty") carved out of Southland's working interests and royalty interests in the properties located in the San Juan Basin in northwestern New Mexico (the "Underlying Properties").

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 Royalty 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 Interest 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 Royalty, 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 and such negative 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 ten 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 the owner of the interest burdened by the Royalty 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%.

The initial carrying value of the Royalty ($133,275,528) represented Southland's historical net book value at the date of the transfer of the Trust. Accumulated amortization as of December 31, 2002 and 2001 aggregated $99,577,622 and $95,415,779 respectively.

3. Basis Of Accounting

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

- Royalty income recorded for a month is the amount computed and paid by the working interest owner, Burlington Resources Oil and Gas Company LP ("BROG"), to the Trustee for the Trust. Royalty income consists of the amounts received by the owner of the interest burdened by the net overriding royalty interest from the sale of production less accrued production costs, development and drilling costs, applicable taxes, operating charges, and other costs and deductions, multiplied by 75%.
- Trust expenses recorded are based on liabilities paid and cash reserves established from Royalty income for liabilities and contingencies.
- Distributions to Unit holders are recorded when declared by the Trustee.
- The conveyance which transferred the overriding royalty interest to the Trust provides that any excess of production costs over gross proceeds must be recovered from future net profits. The financial statements of the Trust differ from financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") because revenues are not accrued in the month of production; certain cash reserves may be established for contingencies which would not be accrued in financial statements prepared in accordance with GAAP; and amortization of the Royalty calculated on a unit-of-production basis is charged directly to trust corpus instead of an expense.

4. Federal Income Taxes

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 Royalty constitutes an "economic interest" in oil and gas properties for federal income tax purposes. Unit holders must report their share of the revenues of the Trust as ordinary income from oil and gas royalties and are entitled to claim depletion with respect to such income. The Royalty is treated as a single property for depletion purposes.

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

The Trust began receiving royalty income from coal seam gas wells in 1989. Under Section 29 of the Internal Revenue Code, coal seam gas production from wells drilled prior to January 1, 1993 (including certain wells recompleted in coal seam formations thereafter) generally qualifies for the federal income tax credit for producing nonconventional fuels if such production and the sale thereof occurs before January 1, 2003. Under current law, coal seam gas production after December 31, 2002, will not qualify for the Section 29 credit. For 2001, this tax credit was approximately $1.08 per MMBtu. For 2002, the amount of the credit will be determined by the Treasury Department no later than April 1, 2003, and, based on historical trends, is expected to approximate (within a 2-3% range) the 2001 credit. The Trust also receives production from wells producing from a tight sands formation. These wells must have been drilled after November 5, 1990, or must have been committed or dedicated to interstate commerce (as defined in Section 2(18) of the Natural Gas Policy Act as in effect November 5, 1990) as of April 20, 1977. This credit is not adjusted for inflation, so the credit remains fixed at .517241 per MMBtu. For qualifying production of the Trust, each Unit holder must determine from the tax information they receive from the Trust, his *pro rata* share of qualifying production of the Trust, based upon the number of Units owned during each month of the year, and the amount of available credit per MMBtu for the year, and apply the tax credit against his own income tax liability, but such credit may not reduce his regular liability (after the foreign tax credit and certain other nonrefundable credits) below his tentative minimum tax. Section 29 also provides that any amount of Section 29 credit disallowed for the tax year solely because of this limitation will increase his credit for prior year minimum tax liability, which may be carried forward indefinitely as a credit against the taxpayer's regular tax liability, subject, however, to the limitations described in the preceding sentence. There is no provision for the carryback or carryforward of the Section 29 credit in any other circumstances.

The Trustee is provided summary Section 29 tax credit information related to Trust properties by BROG, which information is then passed along to the Unit holders. In 1999, the U.S. Court of Appeals for the 10th Circuit upheld the position of the Internal Revenue Service and the Tax Court that nonconventional fuel such as coal seam gas does not qualify for the Section 29 credit unless the producer has received an appropriate well category determination from the Federal Energy Regulatory Commission ("FERC"). The FERC's certification authority expired effective January 1, 1993. However, on July 14, 2000, the FERC issued a final ruling amending its regulations to reinstate certain regulations involving well category determinations for all wells and tight formation areas that could qualify for the Section 29 tax credit. BROG has informed the Trustee that it will seek certification of all qualified wells and that two additional wells were certified in 2002. The classification of the Trust's income for purposes of the passive loss rules may be important to a Unit holder. As a result of the Tax Reform Act of 1986, royalty income will generally be treated as portfolio income and will not reduce passive losses.

5. Litigation Settlement

On September 4, 1996, the Trustee announced the settlement of litigation between the Trust and BROG. In the settlement, BROG agreed (i) to pay $19,750,000 in cash plus interest earning thereon from September 5, 1996, in settlement of underpayment of royalty claims of the Trust; and (ii) commencing in 1997, to credit the Trust with $250,000 per year for five years as an offset against lease operating expenses chargeable to the Trust. BROG also agreed to make certain adjustments that represent cost reductions favorable to the Trust in the ongoing charges for coal seam gas gathering and treating on BROG's Val Verde system. Additionally, the Trustee and BROG established a formal protocol that will provide the Trustee and its representatives improved access to BROG's books and records applicable to the Underlying Properties. The final $250,000 payment was received in 2001. In addition, BROG sold the Val Verde gathering system in 2002, thus increasing costs to the Trust.

Agreement was also reached regarding marketing arrangements for the sale of gas, oil and natural gas liquids products from the Underlying Properties going forward as follows:

1. BROG agreed that contracts for the sale of gas from the Underlying Properties would require the written approval of an independent gas marketing consultant acceptable to the Trust. For a discussion of the current contract covering the sale of gas from the Underlying Properties, see Note 6.

2. BROG will continue to market the oil and natural gas liquids from the Underlying Properties but will remit to the Trust actual proceeds from such sales. BROG will no longer use posted prices as the basis for calculating proceeds to the Trust nor make a deduction for marketing fees associated with sales of oil or natural gas liquids products.

3. The Trust retained access to BROG's current gas transportation, gathering, processing and treating agreements with third parties through the remainder of their primary terms.

6. Certain Contracts

BROG entered into a contract dated November 10, 1999, for the sale of all volumes of Trust gas to Duke Energy and Marketing L.L.C. That contract, as amended, provided for delivery of gas at various delivery points over a period commencing January 1, 2000, and ending March 31, 2002. BROG has subsequently entered into two contracts for the sale of all volumes of gas which are subject to the Royalty. These contracts provide for (i) the sale of Trust gas in two packages to Duke Energy and Marketing L.L.C. and PNM Gas Services, respectively, (ii) the delivery of Trust gas at various delivery points over a period commencing April 1, 2002, and ending March 31, 2004, and (iii) the sale of Trust gas at prices which fluctuate in accordance with published indices for gas sold in the San Juan Basin of New Mexico.

Confidentiality agreements with purchasers of gas produced from the Underlying Properties prohibit public disclosure of certain terms and conditions of gas sales contracts with those entities, including specific pricing terms, gas receipt points, etc. Such disclosure could compromise the ability to compete effectively in the marketplace for the sale of gas produced from the Underlying Properties.

7. Gas Imbalance

In June 2000, the Trust and BROG entered into a partial settlement of claims relating to a gas imbalance with respect to production from mineral properties currently operated by BROG. Under the terms of the partial settlement, BROG paid the Trust $3,490,000 to settle the imbalance insofar as it relates to some of the wells located on the subject properties. The remainder of the imbalance is to be addressed through volume adjustments whereby the Trust's net overriding royalty interest will be applied to 50% of the overproduced parties' interest, on a monthly basis, until the imbalance is corrected. The Trust is in communication with BROG in order to determine the estimated value of the volume adjustments and the time during which the remainder of the imbalance will be corrected.

8. Prior Period Adjustments

Based on its year-end review, BROG has determined that since January of 1999, BROG has undercharged the Trust for both capital expenditures and lease operating charges related to properties burdened by the Trust but not operated by BROG. In April and May of 2000, BROG passed through to the Trust additional charges of $652,303 in capital expenditures and $1,689,509 in lease operating charges related to the under-charged non-operated properties. The Trust's consultants have reviewed BROG's cost reporting data and confirmed that the pass-through of these additional charges was appropriate.

9. Contingencies

Information regarding the status of litigation matters is included in Item 3 of the Trust's annual report on Form 10-K which is included in this report.

10. Commitments And Contingencies

At December 31, 2001, BROG had incurred excess production costs of $2,259,628 on the Underlying Properties due primarily to high capital costs. The Trust conveyance provides for the deduction of excess production costs in determining royalty income until such costs are fully recovered and allows for interest to be charged on excess production costs at the prime rate. Interest in the amount of $10,545 was added to such excess production costs. Of the total, $1,702,630 is attributable to the Trust and has been deducted in determining 2002 royalty income. As a result of settlements agreed to among BROG and other third parties concerning properties burdened by the Royalty, the net profits applicable to the Trust were reduced by approximately $3,624,117. This amount was deducted from the Royalty due the Trust in one million dollar increments in each of May, June and July of 2002, with the balance deducted in August of 2002.

11. Significant Customers

Information as to significant purchasers of oil and gas production attributable to the Trust's economic interests is included in Note 6 above and Item 2 of the Trust's annual report on Form 10-K which is included in this report.

12. 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.

13. Amendments To The Trust's Industries

At a special meeting of Unit holders on September 30, 2002, the Unit holders appointed TexasBank as the successor Trustee of the Trust. The Unit holders also approved amendments to the Trust's Royalty Trust Indenture (the "Indenture") which clarified the language of the Indenture, clarified and expanded the indemnification provisions of the Indenture, and amended the provisions of the Indenture applicable to the fees payable to the Trustee, the investment options available to the Trustee and the manner in which the Trustee can dispose of assets of the Trust.

14. 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, 2002 (in thousands, except unit amounts):

	Royalty Income	Distributable Income	Distributable Income and Distribution Per Unit
2002			
First Quarter	$ 3,925	$ 3,527	$ .075673
Second Quarter	9,560	9,015	.193414
Third Quarter	12,549	12,296	.263820
Fourth Quarter	12,019	11,580	.248447
Total	$38,053	$36,418	$ .781354
2001			
First Quarter	$37,490	$37,262	$ .799474
Second Quarter	26,586	26,251	.563215
Third Quarter	13,972	13,715	.294257
Fourth Quarter	3,321	2,898	.062177
Total	$81,369	$80,126	$1.719123

Independent Auditors' Reports

TexasBank as Trustee for the San Juan Basin Royalty Trust:

We have audited the accompanying statements of distributable income and changes in trust corpus of the San Juan Basin Royalty Trust ("Trust") for the year ended December 31, 2000. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. 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 statement. An audit also includes assessing the accounting principles used and significant estimates made by the Trustee, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As described in Note 3 to the financial statements, these financial statements were prepared on a modified cash basis, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such financial statements present fairly, in all material respects, the distributable income and changes in trust corpus of the San Juan Basin Royalty Trust for the year ended December 31, 2000, on the basis of accounting described in Note 3.

Deloitte & Touche LLP

Deloitte & Touche, L.L.P.
Fort Worth, Texas
March 23, 2001

TexasBank as Trustee for the San Juan Basin Royalty Trust:

We have audited the accompanying statements of assets, liabilities and trust corpus of the San Juan Basin Royalty Trust as of December 31, 2002 and 2001, and the related statements of distributable income and changes in trust corpus for the years then ended. 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 U.S. generally accepted auditing standards. 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 the Trustee, 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 were prepared on a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles.

In our opinion, such financial statements present fairly, in all material respects, the assets, liabilities and trust corpus of the San Juan Basin Royalty Trust as of December 31, 2002 and 2001, and the distributable income and changes in trust corpus for the years then ended, on the basis of accounting described in Note 3 to the financial statements.

Weaver and Tidwell, L.L.P.

Weaver and Tidwell, L.L.P.
Fort Worth, Texas
March 24, 2003

San Juan Basin Royalty Trust
TexasBank, Trustee
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Fort Worth, Texas 76116
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www.sjbrt.com
sjt@texasbank.com

Auditors
Weaver and Tidwell, L.L.P.
Fort Worth, Texas

Legal Counsel
Vinson & Elkins L.L.P.
Dallas, Texas

Tax Counsel
Winstead, Sechrest & Minick, PC
Houston, Texas

Transfer Agent
Computershare Investor Services
Transfer Services
P.O. Box A3480
Chicago, Illinois 60609-3480
For questions about distribution checks, address changes and transfer procedures, call 312-360-5154.

Glossary Of Terms

AGGREGATE MONTHLY DISTRIBUTION: An amount paid to Unit holders equal to the Royalty Income received by the Trustee during a calendar month plus interest, less the general and administrative expenses of the Trust, adjusted by any changes in cash reserves.

BBL: Barrel, generally 42 U.S. gallons measured at 60°F.

BCF: Billion cubic feet.

BROG: Burlington Resources Oil & Gas Company LP.

BTU: British thermal unit; the amount of heat necessary to raise the temperature of one pound of water one degree Fahrenheit.

COAL SEAM WELL: A well completed to a coal deposit found to contain and emit natural gas.

COMMINGLED WELL: A well which produces from two or more formations through a common well casing and a single tubing string.

CONVENTIONAL WELL: A well completed to a formation historically found to contain deposits of oil or gas (for example, in the San Juan Basin, the Pictured Cliffs, Dakota and Mesaverde formations) and operated in the conventional manner.

DEPLETION: The exhaustion of a petroleum reservoir; the reduction in value of a wasting asset by removing minerals; for tax purposes, the removal and sale of minerals from a mineral deposit.

DISTRIBUTABLE INCOME: An amount paid to Unit holders equal to the royalty income received by the Trustee during a given period plus interest, less the general and administrative expenses of the Trust, adjusted by any changes in cash reserves.

DUAL COMPLETION: The completion of a well into two separate producing formations at different depths, generally through one string of pipe producing from one of the formations, inside of which is a smaller string of pipe producing from the other formation.

ESTIMATED FUTURE NET REVENUES: An estimate 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; sometimes referred to as "estimated future net cash flows."

GRANTOR TRUST: A trust (or portion thereof) with respect to which the grantor or an assignee of the grantor, rather than the trust, is treated as the owner of the trust properties and is taxed directly on the trust income for federal income tax purposes under Sections 671 through 679 of the Internal Revenue Code.

GROSS ACRES OR WELLS: The interests of all persons owning interests in such acres or wells.

GROSS PROCEEDS: The amount received by BROG (or any subsequent owner of the Underlying Interests) from the sale of the production attributable to such interests.

INFILL DRILLING: The drilling of wells intended to be completed to proven reservoirs or formations, sometimes occurring in conjunction with regulatory approval for increased density in the spacing of wells.

LEASE OPERATING EXPENSES: Expenses incurred in the operation of a producing property as apportioned among the several parties in interest.

MCF: 1,000 cubic feet; the standard unit for measuring the volume of natural gas.

MMBTU: One million British thermal units.

MULTIPLE COMPLETION WELL: A well which produces simultaneously through separate tubing strings from two or more producing horizons or alternatively from each.

NET ACRES OR WELLS: The interests of BROG in such acres or wells.

NET OVERRIDING ROYALTY INTEREST: A share of gross production from a property, measured by net profits from operation of the property and carved out of the working interest, i.e., a net profits interest.

NET PROCEEDS: The excess of Gross Proceeds received by BROG during a particular period over Production Costs for such period.

PAYADD: Completion in an existing well of additional productive zone(s) within a producing formation.

PRESENT VALUE OF ESTIMATED FUTURE NET REVENUES: The present value of the Estimated Future Net Revenues computed using a discount rate of 10%.

PRODUCTION COSTS: Costs incurred on an accrual basis by BROG in operating the Underlying Properties, including both capital and non-capital costs and including, for example, development drilling, production and processing costs, applicable taxes and operating charges.

PROVED DEVELOPED RESERVES: Those Proved Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

PROVED RESERVES: 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 UNDEVELOPED RESERVES: 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.

RECAVITATED WELL: A coal seam well, the production from which has been enhanced or extended by the enlargement of the cavity within the coal deposit to which the well has been completed.

RECOMPLETED WELL: A well completed by drilling a separate well-bore from an existing casing in order to reach the same reservoir, or re-drilling the same well bore to reach a new reservoir after production from the original reservoir has been abandoned.

ROYALTY: The principal asset of the Trust; the 75% net overriding royalty interest conveyed to the Trust on November 3, 1980, by Southland Royalty Company, the predecessor to BROG, which was carved out of the Underlying Interests.

ROYALTY INCOME: The monthly Net Proceeds attributable to the Royalty.

SECTION 29 TAX CREDIT: A federal income tax credit available under Section 29 of the Internal Revenue Code for producing coal seam gas (and other nonconventional fuels) from wells drilled prior to January 1, 1993, to a formation beneath a qualifying coal seam formation, and for production from wells drilled after December 31, 1979, but prior to January 1, 1993, which are later completed into such a formation.

SPOT PRICE: The price paid for gas, oil or oil products sold under contracts for the purchase and sale of such minerals on a short-term basis.

UNDERLYING INTERESTS: The working, royalty and other interests owned by Southland Royalty Company, the predecessor to BROG, in properties located in the San Juan Basin of northwest New Mexico, out of which the Royalty was carved.

UNDERLYING PROPERTIES: The real property located in the San Juan Basin of northwestern New Mexico burdened by the Underlying Interests.

UNITS OF BENEFICIAL INTEREST: The units of ownership of the Trust, equal to the number of shares of common stock of Southland Royalty Company outstanding at the close of business on November 3, 1980.

WORKING INTEREST: The operating interest under an oil and gas lease.

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

Form 10-K/A

(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, 2002

or

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

For the transition period from to

Commission file number 1-8032

San Juan Basin Royalty Trust
(Exact name of registrant as specified in the Amended and Restated San Juan Basin Royalty Trust Indenture)

Texas	**75-6279898**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
TexasBank, Trust Department **2525 Ridgmar Boulevard, Suite 100** **Fort Worth, Texas**	**76116**
(Address of principal executive offices)	*(Zip Code)*

(866) 809-4553
(Registrant's telephone number, including area code)

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

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

Securities registered pursuant to Section 12(g) of the Act:
None
(Title of Class)

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. Yes ☑ No ☐

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

State the aggregate market value of the Units of Beneficial Interest held by non-affiliates of the Registrant as of June 28, 2002: $515,959,372.

At March 25, 2003, there were 46,608,796 Units of Beneficial Interest of the Trust outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

"Units of Beneficial Interest" at page 1; "Description of the Properties" at pages 5 and 6; "Trustee's Discussion and Analysis" at pages 7, 8 and 9; "Results of the 4th Quarters of 2002 and 2001" at page 10; and "Statements of Assets, Liabilities and Trust Corpus," "Statements of Distributable Income," "Statements of Change in Trust Corpus," "Notes to Financial Statements," and "Independent Auditor's Report" at page 11 et seq., in registrant's Annual Report to Unit Holders for the year ended December 31, 2002 are incorporated herein by reference for Item 2 (Properties) and Item 3 (Legal Proceedings) of Part I of this Report, and Item 5 (Market for Units of the Trust and Related Security Holder Matters), Item 7 (Management's Discussion and Analysis of Financial Condition and Results of Operation) and Item 8 (Financial Statements and Supplementary Data) of Part II of this Report.

EXPLANATORY NOTE

This Amendment No. 1 to the San Juan Basin Royalty Trust's Annual Report on Form 10-K for its fiscal year ended December 31, 2002 is being filed to amend the estimated future net revenues and present value of estimated future net revenues table on page 9 of the Annual Report solely to revise the 2002 per Unit information. This Amendment No. 1 does not reflect events occurring after the filing of the original Form 10-K and does not modify or update the disclosures in the original Form 10-K in any way other than as described in this Explanatory Note.

PART I

Certain information included in this Annual Report on Form 10-K/A contains, and other materials filed or to be filed by the San Juan Basin Royalty Trust (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, and Section 27A of the Securities Act of 1933. 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. Such forward-looking statements generally are accompanied by words such as "may," "will," "estimate," "expect," "predict," "anticipate," "goal," "should," "assume," "believe," "plan," "intend," or other words that convey the uncertainty of future events or outcomes. Such statements reflect Burlington Resources Oil & Gas Company LP's ("BROG"), the working interest owner's, current view with respect to future events; are based on an assessment of, and are subject to, a variety of factors deemed relevant by TexasBank, the Trustee of the Trust, and BROG and involve risks and uncertainties. Should one or more of these risks or uncertainties occur, actual results may vary materially and adversely from those anticipated.

Item 1. *Business*

The Trust is an express trust created under the laws of the state of Texas by the San Juan Basin Royalty Trust Indenture (the "Original Indenture") entered into on November 3, 1980, between Southland Royalty Company ("Southland Royalty") and the Fort Worth National Bank. Effective as of September 30, 2002, the Original Indenture was amended and restated (the Original Indenture, as amended and restated, the "Trust Indenture"). The Trustee of the Trust is TexasBank. The principal office of the Trust is located at 2525 Ridgmar Boulevard, Suite 100, Fort Worth, Texas 76116, Attention: Trust Department (telephone number (866) 809-4553). The Trust maintains a website at *www.sjbrt.com.* The Trust makes available (free of charge) its annual, quarterly and current reports (and any amendments thereto) filed with the Securities and Exchange Commission (the "SEC") on its website as soon as reasonably practicable after electronically filing such material with, or furnishing it to, the SEC.

On October 23, 1980, the stockholders of Southland Royalty approved and authorized that company's conveyance of a net overriding royalty interest (equivalent to a net profits interest) 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 oil and gas leasehold and royalty interests (the "Underlying Interests") in properties located in the San Juan Basin of northwestern New Mexico (the "Underlying Properties"). The conveyance of this net overriding royalty interest (the "Royalty") was made on November 3, 1980, effective as to production from and after November 1, 1980 at 7:00 A.M.

The Royalty was carved out of and now burdens those properties and interests as more particularly described under "Item 2. Properties" herein.

The Royalty constitutes the principal asset of the Trust and the beneficial interests in the Royalty 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. Holders of Units are referred to herein as "Unit Holders."

The function of the Trustee is to collect the income attributable to the Royalty, 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.

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 these transactions, Meridian Oil, Inc. ("MOI") also became an indirect subsidiary of BRI. Effective January 1, 1996, Southland Royalty, a wholly-owned subsidiary of MOI, was merged with and into MOI, by which action the separate corporate existence of Southland Royalty ceased to exist and MOI survived and succeeded to the ownership of all of the assets, rights, powers and privileges and assumed all of the liabilities and obligations of Southland Royalty. Subsequent to the merger, MOI changed its name to BROG.

The term "net proceeds," as used in the November 3, 1980 conveyance, 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 Interests) from the sale of the production attributable to the Underlying Interests subject to certain adjustments. "Production costs" generally means costs incurred on an accrual basis by BROG in operating its properties and interests out of which the Royalty was carved, including both capital and non-capital costs. For example, these costs include 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 otherwise liable for any production costs or other 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 under the Royalty, it shall not be obligated to return such overpayment, but the amounts payable to it for any subsequent period shall be reduced by such amount, plus interest, at a rate specified in the conveyance.

Certain of the Underlying Interests are operated by BROG with the obligation to conduct its operations in accordance with reasonable and prudent business judgment and good oil and gas field practices. As operator, BROG has the right to abandon any well when, in its opinion, such well ceases to produce or is not capable of producing oil and gas in paying quantities. BROG also is responsible, subject to the terms of a settlement agreement with the Trust, for marketing the production from such properties, 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 interest 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 Royalty 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) the net proceeds attributable to the Royalty paid to the Trustee, 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 being 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, in the Trustee's discretion, in obligations issued by (or unconditionally guaranteed by) the United States or any agency thereof, repurchase agreements secured by obligations issued by the United States or any agency thereof, certificates of deposit of banks having capital, surplus and undivided profits in excess of $50,000,000, or money market funds that have been rated AAAmg or AAAm by Standard & Poor's and AA by Moody's, subject, in each case, to certain other qualifying conditions.

The Underlying Properties are primarily gas producing properties. Normally there is a greater demand for gas in the winter months than during the rest of the year. Otherwise, the income to the Trust attributable to the Royalty is not subject to seasonal factors nor in any manner related to or dependent upon patents, licenses, franchises or concessions. The Trust conducts no research activities.

Based on its 1999 year-end review, BROG determined that it had undercharged the Trust for both capital expenditures and lease operating charges related to properties burdened by the Trust but not operated by BROG. In April and May of 2000, BROG passed through to the Trust additional charges of $652,303 in capital expenditures and $1,689,509 in lease operating charges related to the undercharged non-operated properties. The Trust's consultants have reviewed BROG's cost reporting data and confirmed that these additional charges were appropriate.

Item 2. *Properties*

The Royalty conveyed to the Trust was carved out of Southland Royalty's (now BROG's) working interests and royalty interests in certain properties situated in the San Juan Basin in northwestern New Mexico. References below to "gross" wells and acres are to the interests of all persons owning interests therein, while references to "net" are to the interests of BROG (from which the Royalty was carved) in such wells and acres.

Unless otherwise indicated, the following information in Item 2 is based upon data and information furnished to the Trustee by BROG.

Producing Acreage, Wells and Drilling

The Underlying Interests consist of working interests, royalty interests, overriding royalty interests and other contractual rights in 151,900 gross (119,000 net) producing acres in San Juan, Rio Arriba and Sandoval Counties of northwestern New Mexico. Based upon information received from the Trust's independent petroleum engineers, as of December 31, 2002, the Trust properties contain 3,738 gross (1,135 net) economic wells, including dual completions. Production from conventional gas wells is primarily from the Pictured Cliffs, Mesaverde and Dakota formations. During 1988, Southland Royalty began development of coal seam reserves in the Fruitland Coal formation. For additional information concerning coal seam gas, the "Description of the Properties" section of the Trust's Annual Report to security holders for the year ended December 31, 2002, is herein incorporated by reference.

The Royalty conveyed to the Trust is limited to the base of the Dakota formation, which is currently the deepest significant producing formation under acreage affected by the Royalty. Rights to production, if any, from deeper formations are retained by BROG.

In February 2002, BROG announced an estimated capital budget for the Underlying Properties of $17.1 million. During the year the estimate was initially reduced to $12.4 million and ultimately increased to $19.0 million. BROG's capital plan for the Underlying Properties for 2002 estimated 397 projects, including the drilling of 54 new wells operated by BROG and 26 wells operated by third parties. In 2002, BROG actually participated in 339 projects, including 41 new wells operated by BROG and 12 wells operated by third parties. BROG reported that the swings in the budget estimates related in large part to whether and when BROG was successful in obtaining the necessary governmental and landowner approvals to drill on a well-by-well basis.

An aggregate of $21.5 million in capital expenditures were reported by BROG in calculating payments to the Trust for 2002. This amount included approximately $10.1 million attributable to the capital budgets for prior years. This occurs because projects within a given year's budget may extend into subsequent years, with capital expenditures attributable to those projects used in calculating distributable income to the Trust in those subsequent years. Further, BROG's accounting period for capital expenditures runs through November 30 of each calendar year, such that capital expenditures incurred in December of each year are actually accounted for as part of the following year's capital expenditures. Also, for wells not operated by BROG, BROG's share of capital expenditures may not actually be paid by it until the year or years after those expenses were incurred by the operator. Capital expenditures of approximately $11.4 million for 2002 budgeted projects were used in calculating distributable income in calendar year 2002, and approximately $3.6 million in capital expenditures have been used in calculating distributions for the first three months of 2003. Therefore, an additional approximately $4.0 million in capital expenditures for 2002 projects remains to be spent.

During 2002, in calculating the net proceeds to the Trust, BROG deducted approximately $21.5 million of capital expenditures for projects, including drilling and completion of 98 gross (30.05 net) conventional wells, recompletion of 36 gross (14.44 net) conventional wells, 13 gross (2.21 net) miscellaneous capital projects, one gross (.82 net) restimulation, one gross (.05 net) payadd, 16 gross (5.42 net) coal seam wells, 11 gross (1.45 net) miscellaneous coal seam capital projects, 14 gross (5.77 net) coal seam recompletions, five gross (.98 net) coal seam recavitations, three gross (.01 net) coal seam restimulations and facilities maintenance. There were 61 gross (24.49 net) new conventional wells, 20 gross (4.69 net) conventional well recompletions, 65 gross (19.82 net) miscellaneous conventional capital projects, four gross (1.41 net) coal seam wells, two gross (.99 net) coal seam recompletions, and five gross (1.72 net) miscellaneous coal seam capital projects in progress as of December 31, 2002.

During 2001, in calculating the net proceeds to the Trust, BROG deducted approximately $33 million of capital expenditures for projects, including drilling and completion of 92 gross (36.33 net) conventional wells, recompletion of 33 gross (18.18 net) conventional wells, 13 gross (2.85 net) miscellaneous capital projects, three gross (2.34 net) restimulations, 56 gross (8.40 net) conventional payadds, ten gross (1.52 net) coal seam wells, four gross (1.61 net) coal seam well recompletions, one gross (.88 net) coal seam payadd, six gross (.04 net) coal seam recavitations and facilities maintenance. There were 100 gross (32.47 net) new conventional wells, 31 gross (13.47 net) conventional well recompletions, two gross (.87 net) miscellaneous conventional capital projects, nine gross (3.17 net) conventional payadds, 15 gross (1.09 net) conventional restimulations, 12 gross (5.36 net) coal seam wells, seven gross (4.11 net) coal seam recompletions, two gross (.02 net) coal seam restimulations and six gross (.29 net) miscellaneous coal seam capital projects in progress as of December 31, 2001.

BROG has informed the Trust that its projections for capital expenditures for the Underlying Properties in 2003 is estimated at $14.1 million. BROG anticipates 351 projects, including the drilling of 38 new wells to be operated by BROG and 26 wells to be operated by third parties. Of the new BROG operated wells, 14 are projected to be conventional wells completed to the Pictured Cliffs, Mesaverde, and/or Dakota formations, and the remaining 24 are projected as coal seam gas wells to be completed in the Fruitland Coal formation. A total of 21 of the wells operated by third parties are projected to be conventional wells and the remaining five are to be coal seam wells. BROG projects approximately $10.5 million to be spent on new wells, and $3.6 million to be expended in working over existing wells and in the maintenance and improvement of production facilities.

In October 2002, the New Mexico Oil Conservation Division approved reduced, 160-acre spacing in selected portions of the Fruitland Coal formation. BROG has informed the Trust that, principally as a result of this approval, its budget for 2003 reflects a focus on the Fruitland Coal formation. In February 2002, BROG informed the Trust that the New Mexico Oil Conservation Division had approved plans for 80-acre infill drilling of the Dakota formation in the San Juan Basin. The New Mexico Oil Conservation has asked BROG and other interested parties to study over the next year whether the change in spacing requirements should be expanded to cover other portions of that reservoir. Eighty-acre spacing has been permitted in the Mesaverde formation since 1997.

BROG has previously informed the Trust that increases in its capital program, particularly in 2001 and 2002, were designed to offset the natural decline in production from the Underlying Properties. BROG has reported favorable results in this effort in that natural gas production for calendar year 2002 averaged approximately 127 MMcf per day, as compared to average production of approximately 121 MMcf per day for calendar 2001, and 116 MMcf per day for calendar 2000.

BROG indicates its budget for 2003 reflects continued significant development of properties in which the Trust's net overriding royalty interest is relatively high, a sustained focus on conventional formations, including infill drilling to the Mesaverde and Dakota formations, development of the Fruitland Coal formation and multiple formation completions.

Oil and Gas Production

The Trust recognizes production during the month in which the related net proceeds attributable to the Royalty are paid to the Trust. Production of oil and gas and related average sales prices attributable to the Royalty for the three years ended December 31, 2002 were as follows:

	2002		2001		2000	
	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)
Production	40,215	19,584,056	42,056	19,272,021	47,441	20,317,750
Average Price	$ 20.90	$ 2.32	$ 24.99	$ 4.61	$ 24.66	$ 2.99

Pricing Information

Gas produced in the San Juan Basin is sold in both interstate and intrastate commerce. Reference is made to the discussion contained herein under "Regulation" for information as to federal regulation of prices of oil and natural gas. Gas production from the properties from which the Royalty was carved totaled 46,206,298 Mcf during 2002.

On September 4, 1996, the Trustee announced a settlement of litigation filed by the Trustee against BROG and Southland Royalty Company. In the settlement, agreement was reached, among other things, regarding marketing arrangements for the sale of those gas, oil and natural gas liquids products which are subject to the Royalty (the "Trust" gas, oil and/or natural gas liquids) as follows:

(i) BROG agreed that all subsequent contracts for the sale of Trust gas would require the written approval of an independent gas marketing consultant acceptable to the Trust;

(ii) BROG will continue to market the Trust oil and natural gas liquids but will make payments to the Trust based on actual proceeds from such sales, and BROG will no longer use posted prices as the basis for calculating proceeds to the Trust nor make a deduction for marketing fees associated with sales of oil or natural gas liquids products; and

(iii) The independent marketer of the Trust gas is entitled to use of BROG's current gas transportation, gathering, processing and treating agreements with third parties, at least through the remainder of their primary terms.

See Note 5 of Notes to Financial Statements of the Trust's Annual Report to security holders for the year ended December 31, 2002 for further discussion of this settlement and its impact on the Trust.

BROG has entered into two contracts for the sale of all Trust gas. These contracts provide for (i) the sale of Trust gas in two packages to Duke Energy and Marketing, L.L.C. and PNM Gas Services, respectively, (ii) the delivery of Trust gas at various delivery points over a period commencing April 1, 2002, and ending March 31, 2004, and (iii) the sale of Trust gas at prices which fluctuate in accordance with published indices for gas sold in the San Juan Basin of New Mexico.

Confidentiality agreements with purchasers of gas produced from the Underlying Properties prohibit public disclosure of certain terms and conditions of gas sales contracts with those entities, including specific pricing terms, gas receipt points, etc. Such disclosure could compromise the ability to compete effectively in the marketplace for the sale of gas produced from the Underlying Properties.

Oil and Gas Reserves

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

"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 in this Form 10-K as "estimated future net cash flows."

"Present value of estimated future net revenues" is computed using the estimated future net revenues (as defined above) and a discount rate of 10%.

"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.

The independent petroleum engineers' reports as to the proved oil and gas reserves as of December 31, 2000, 2001 and 2002 were prepared by Cawley, Gillespie & Associates, Inc. The following table presents a reconciliation of proved reserve quantities attributable to the Royalty from December 31, 1999 to December 31, 2002 (in thousands):

	Crude Oil (Bbls)	Natural Gas (Mcf)
Reserves as of December 31, 1999	450	214,215
Revisions of previous estimates	199	73,803
Extensions, discoveries and other additions	80	36,207
Production	(47)	(20,318)
Reserves as of December 31, 2000	682	302,907
Revisions of previous estimates	(272)	(116,270)
Extensions, discoveries and other additions	15	9,450
Production	(42)	(19,272)
Reserves as of December 31, 2001	383	176,815
Revisions of previous estimates	86	60,402
Extensions, discoveries and other additions	19	17,833
Production	(40)	(19,584)
Reserves as of December 31, 2002	448	235,466

Estimated quantities of proved developed reserves of crude oil and natural gas as of December 31, 2002, 2001 and 2000 were as follows (in thousands):

	Crude Oil (Bbls)	Natural Gas (Mcf)
2002	415	209,665
2001	356	162,577
2000	624	277,459

Generally, the calculation of oil and gas reserves takes into account a comparison of the value of the oil or gas to the cost of producing those minerals, in an attempt to cause minerals in the ground to be included in reserve estimates only to the extent that the anticipated costs of production will be exceeded by the anticipated sales revenue. Accordingly, an increase in sales price and/or a decrease in production cost can itself result in an increase in estimated reserves and declining prices and/or increasing costs can result in reserves reported at less than the physical volumes actually thought to exist. 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 estimated 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 net cash flows relating to proved oil and gas reserves.

Estimates of proved oil and gas reserves are by their nature imprecise. Estimates of future net revenue attributable to proved reserves are sensitive to the unpredictable prices of oil and gas and other variables. Accordingly, under the allocation method used to derive the Trust's quantity of proved reserves, changes in prices will result in changes in quantities of proved oil and gas reserves and estimated future net revenues.

The 2002, 2001 and 2000 changes in the standardized measure of discounted future net cash flows related to future royalty income from proved reserves discounted at 10% are as follows (in thousands):

	2002	2001	2000
Balance, January 1	$173,846	$818,212	$229,721
Revisions of prior-year estimates, change in prices and other	233,062	(652,337)	530,811
Extensions, discoveries and other additions	25,642	7,519	94,753
Accretion of discount	17,385	81,821	22,972
Royalty income	(38,053)	(81,369)	(60,045)
Balance, December 31	$411,882	$173,846	$818,212

Reserve quantities and revenues shown in the tables above for the Royalty were estimated from projections of reserves and revenues attributable to the combined BROG and Trust interests. Reserve quantities attributable to the Royalty were derived from estimates by allocating to the Royalty a portion of the total net reserve quantities of the interests, based upon gross revenue less production taxes. Because the reserve quantities attributable to the Royalty 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 Royalty. Therefore, the reserve quantities estimated will vary if different future price and cost assumptions occur. The future net cash flows were determined without regard to future federal income tax credits available to production from coal seam wells.

December average prices of $3.75 per Mcf of conventional gas, $2.80 per Mcf of coal seam gas and $24.88 per Bbl of oil were used at December 31, 2002, in determining future net revenue. The upward revision in reserve quantities for 2002 as compared to 2001 is primarily due to significantly higher oil and gas prices in December 2002 as compared to December 2001.

December average prices of $1.96 per Mcf of conventional gas, $1.42 per Mcf of coal seam gas and $15.79 per Bbl of oil were used at December 31, 2001, in determining future net revenue. The downward revision in reserve quantities for 2001 as compared to 2000 is primarily due to significantly lower oil and gas prices in December 2001 as compared to December 2000.

December average prices of $6.18 per Mcf of conventional gas, $4.03 per Mcf of coal seam gas and $24.67 per Bbl of oil were used at December 31, 2000, in determining future net revenue.

The following presents estimated future net revenues and present value of estimated future net revenues attributable to the Royalty for each of the years ended December 31, 2002, 2001 and 2000 (in thousands except amounts per Unit):

	2002		2001		2000	
	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	$737,639	$411,882	$290,582	$173,846	$1,580,837	$818,212
Proved Developed	$661,634	$378,285	$266,834	$164,164	$1,445,557	$752,825
Total Proved Per Unit	$ 15.83	$ 8.84	$ 6.23	$ 3.73	$ 33.92	$ 17.55

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 above estimates. 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.

Regulation

Many aspects of the production, pricing 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 BROG can produce and to limit the number of wells or the locations at which BROG can drill.

Federal Natural Gas Regulation

The transportation and sale for resale of natural gas in interstate commerce, historically, have been regulated pursuant to several laws enacted by Congress and the regulations promulgated under these laws by the Federal Energy Regulatory Commission ("FERC") and its predecessor. In the past, the federal government has regulated the prices at which gas could be sold. Congress removed all non-price controls affecting wellhead sales of natural gas effective January 1, 1993. Congress could, however, reenact price controls in the future.

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 FERC from 1985 to the present that affect the economics of natural gas production, transportation, and sales. In addition, 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 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.

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, 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 pursued over the last decade by FERC and Congress will continue.

Sales of crude oil, condensate and gas liquids are not currently regulated and are made at market prices. The ability to transport and sell petroleum products are dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. Certain regulations implemented by FERC in recent years could result in an increase in the cost of transportation service on certain petroleum products pipelines.

Section 29 Tax Credit

The Trust began receiving royalty income from coal seam gas wells in 1989. Under Section 29 of the Internal Revenue Code, coal seam gas production from wells drilled prior to January 1, 1993 (including certain wells recompleted in coal seams formations thereafter), generally qualifies for the federal income tax credit for producing non-conventional fuels if such production and the sale thereof occurs before January 1, 2003. Thus, under current law, coal seam gas production after December 31, 2002 will not qualify for the Section 29 credit. For 2001, this tax credit was approximately $1.08 per MMBtu. For 2002, the amount of the credit will be determined by the Treasury Department no later than April 1, 2003, and, based on historical trends, is expected to approximate (within a 2-3% range) the 2001 credit.

To benefit from the credit, each Unit Holder must determine from the tax information he receives from the Trust his pro rata share of qualifying production of the Trust, based upon the number of Units owned during each month of the year, and the amount of available credit per MMbtu for the year, and then apply the tax credit against his own income tax liability, but such credit may not reduce his regular tax liability (after the foreign tax credit and certain other nonrefundable credits) below his tentative minimum tax. Section 29 also provides that any amount of Section 29 credit disallowed for the tax year solely because of this limitation will increase his credit for prior year minimum tax liability, which may be carried forward indefinitely as a credit against the taxpayer's regular tax liability, subject, however, to the limitations described in the preceding sentence. There is no provision for the carryback or carryforward of the Section 29 credit in any other circumstances.

BROG provides the Trustee with certain Section 29 tax credit information, including qualifying coal seam volumes produced from Underlying Properties. In 1999, the Tenth Circuit Court upheld the position of the IRS and the Tax Court that nonconventional fuel such as coal seam gas does not qualify for the Section 29 credit unless the producer received a formal certification from FERC. FERC's certification authority expired effective January 1, 1993. However, on July 14, 2000, FERC issued a final ruling amending its regulations to reinstate certain regulations involving well category determinations for all wells and tight formation areas that could qualify for the Section 29 tax credit. BROG has informed the Trustee that it will seek certification of all qualified wells and that two additional wells were certified in 2002.

Other Regulation

The oil and natural gas 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.

Item 3. *Legal Proceedings*

Settlements

As part of the September 4, 1996 settlement of the litigation filed by the Trustee on June 4, 1992, against BROG and Southland Royalty Company, the Trust was entitled to certain adjustments (the "Val Verde Credit") that represented cost reductions favorable to the Trust in the charges for coal seam gas gathered and treated on BROG's Val Verde system. The settlement provided that the Val Verde Credit was applicable until the later of July 1, 2002 or until BROG no longer owned the Val Verde facility. By correspondence dated July 15, 2002, BROG notified the Trustee of the sale of the Val Verde facility to TEPPCO Partners, L.P. effective July 1, 2002. Accordingly, effective July 1, 2002, the calculation of net proceeds for gas gathered and treated at the Val Verde facility no longer includes the Val Verde Credit. The total annual amount of the Val Verde Credit has been estimated by the Trust's joint interest auditors as approximately $2.0 million. The loss of the Val Verde Credit will result in increased costs allocated to the Trust for coal seam gas gathered and treated on the Val Verde system and accordingly, will decrease the royalty income received by the Trust.

An administrative claim was initiated on March 17, 1997, by the Mineral Management Service of the United States Department of the Interior (the "MMS") against BROG regarding a gas contract settlement dated March 1, 1990, between BROG and certain other parties thereto. The claim alleged that additional royalties were due on production from federal and Indian leases in the State of New Mexico on properties burdened by the Trust. On December 3, 2001, BROG settled this claim by paying the Jicarilla Apache Nation the sum of $2,853,974 and the MMS the sum of $1,224,043. MMS also retained certain overpayments by BROG in the amount of $1,127,623 as part of the settlement. Certain properties included in this settlement are burdened by the Royalty. BROG has offset the entire $2,853,974 Jicarilla component of the settlement against amounts otherwise distributed in payment of the Royalty, and has informed the Trust that the $1,224,043 paid to the MMS is also allocable to the Royalty. BROG has indicated that it does not appear that any of the $1,127,623 in overpayments retained by the MMS is attributable to the Royalty.

In another proceeding involving BROG and the Jicarilla Apache Nation, the MMS entered an Order to Perform on June 10, 1998, stating that, in valuing production for royalty purposes, BROG must perform, among other things, a "dual accounting" calculation (i.e., compute royalties on the greater of the value of gas prior to processing or the combined value of processed residue gas and plant products plus the value of any condensate recovered downstream without processing). In December 2000, BROG and the Jicarilla Apache Nation entered into a settlement resolving the issues associated with the dual accounting calculation. Under the settlement, BROG paid $3,260,366 to the Jicarilla Apache Nation. BROG has allocated $1,978,182 of the settlement payment to the Royalty.

Beginning in May 2002, BROG deducted the lesser of $1 million or 50% of the monthly net proceeds from the monthly net proceeds otherwise payable to the Trust until an aggregate of $3,624,117 was deducted. BROG deducted $1 million from each of the monthly net proceeds payments to the Trust in May, June and July of 2002, and the balance in August of 2002. These deductions represented the Trust's share of the settlements.

In June 2000, the Trust and BROG entered into a partial settlement of claims relating to a gas imbalance with respect to production from mineral properties currently operated by BROG. Under the terms of the partial settlement, BROG paid the Trust $3,490,000 to settle the imbalance insofar as it relates to some of the wells located on the Underlying Properties. The remainder of the imbalance is to be addressed through volume adjustments whereby the Trust's Royalty will be increased by the proceeds from 50% of the overproduced parties' interest, on a monthly basis, until the imbalance is corrected. The Trustee and its consultants remain in communication with BROG in order to determine the estimated value of the volume adjustments and the time during which the remainder of the imbalance will be corrected. BROG indicates that the volume adjustment commenced in August 2000. The Trust's consultants continue to monitor those adjustments.

Administrative Proceedings

The following information was provided to the Trust by BROG. Please note that the proceedings described below apply to the collective interest of BROG and the Trust. BROG is not able to estimate the amount of any potential loss to the Trust in each of the outstanding proceedings, or the portion of any such potential loss that would be allocated to the Royalty.

MMS Proceedings

Blanco Pool. This appeal arises from a MMS Demand Letter dated October 20, 1995, and bears MMS Appeal Docket No. MMS-95-0740. The demand letter challenges the "valuation benchmark" utilized by BROG for gas sold by BROG from the "Blanco Pool" during the audit period of January 1, 1989 through December 31, 1991. BROG paid royalties on sales to its marketing affiliate based on "gross proceeds" received by BROG from its affiliate. The demand letter states that BROG paid incorrectly under MMS regulations. The MMS methodology in calculating the amounts demanded does not attempt to trace resale proceeds. Instead, MMS' auditors use published index prices at pipeline interconnect points in the San Juan Basin as a proxy for actual comparable sales, and net out certain actual costs to move the gas to those index points. While BROG had deducted prevailing field transportation rates in computing its monthly prices in the San Juan Basin, the auditors limited the deduction to the actual rate paid to El Paso Natural Gas under a "backhaul" agreement. The demand letter directs BROG to pay additional royalties of $518,304, to recalculate royalties in accordance with the MMS' interpretation of the regulations and to pay the difference between total royalty due and royalty paid.

Affiliate Proceeds Demand — Conventional Gas. This appeal arises from a MMS demand letter dated June 9, 1997, and bears MMS Appeal Docket No. MMS-97-0168. The demand letter is a blanket demand relating to all of BROG's non-coalbed methane gas production nationwide for the audit period of January 1, 1989 through December 31, 1994. The demand letter is based primarily on the MMS theory that royalties are to be based on BROG's marketing affiliate gross proceeds rather than BROG's gross proceeds (e.g. the affiliate resale proceeds issue). The demand letter directs BROG to recalculate its royalties on these sales using a netback calculation of the proceeds of the affiliate, and pay the difference between total royalties due under such calculation and the royalties actually paid by BROG. This demand letter is in furtherance of the demand letter described in the prior paragraph.

Coalbed Methane. This appeal arises from a MMS demand letter dated October 28, 1996, and bears MMS Appeal Docket No. MMS-96-0437. The demand letter relates to BROG's coalbed methane production from the Northeast Blanco Unit for the audit period of May 1, 1990 through December 31, 1993, and from the San Juan 30-6 Unit for the audit period of January 1, 1989 through December 31, 1991. Like the Blanco Pool demand letter, the demand letter does not attempt to trace resale proceeds. The issues are whether MMS should bear its share of CO_2 extraction costs and, if so, whether the costs should be based on market rates or actual costs of the system, and whether MMS' share of transportation costs (which MMS does not dispute it must bear) should be based on market rates or actual costs of the system. BROG is directed to pay additional royalties of $3,600,584 for underpayment of royalty for gas produced from the units mentioned above, to recalculate royalties for gas produced from other federal leases in accordance with MMS' interpretation of the regulations and to pay the difference between total royalty due and royalty paid.

Due to the similarity of the claims in the Blanco Pool, Affiliate Proceeds Demand and the Coalbed Methane administrative appeals, to the claims in the suits in the In re Natural Gas Royalties qui tam litigation described below, settlement discussions between BROG and the federal government in the gas qui tam litigation will, if successful, include the settlement of each of the MMS Proceedings.

Jicarilla Indian Tribe Proceedings

This appeal arises from an MMS Order to Perform dated June 10, 1998. The Order to Perform states that, in valuing production for royalty purposes, BROG must, among other things, perform a major portion analysis (i.e., calculate value on the highest price paid or offered for a major portion of the gas produced from the field where the leased lands are situated). BROG believes that producers do not have access to prices received by other producers in a field, so a major portion calculation must be done by MMS.

Litigation

Grynberg Litigation

In September 1998, BROG was advised by the United States Department of Justice under an order of confidentiality that a lawsuit styled *United States of America ex rel. Jack J. Grynberg v. Burlington Resources Oil & Gas, et al.*, Civil Action No. 97-CV-189 and 190, United States District Court for the District of Wyoming, had been filed under seal pursuant to the qui tam provisions of the civil federal False Claims Act, and that seventy-seven similar cases had been filed by the plaintiff against other companies. The complaint alleges that BROG engaged in the mismeasurement of volumes and wrongful analysis of heating content of natural gas and engaged in other activities, including the sale of natural gas to affiliated companies, which resulted in the underpayment of royalties to the United States. The government investigated the plaintiff's claims, and in May 1999 issued notice that the United States would not intervene in the case. The lawsuits have been unsealed by the court and the plaintiff has served the complaint on BROG. This claim was subsequently consolidated into a multi-district litigation proceeding as described below.

In re Natural Gas Royalties Qui Tam Litigation

On March 28, 2000, the United States District Court for the Eastern District of Texas, Lufkin Division, ordered that the first amended complaint in the case of *United States ex rel. M. Glenn Osterhoudt, III v. Amerada Hess, et al.*, Civil Action No. 9:98CV101, in the United States District Court for the Eastern District of Texas, Lufkin Division, and the second amended complaint in the case of *United States of America ex rel. Harrold E. (Gene) Wright v. Agip Petroleum Burlington, et al.*, Civil Action No. C-5:96CV243 be unsealed and served upon defendants, including BROG. In these lawsuits, the plaintiffs have alleged violations of the civil False Claims Act. Plaintiffs contend that defendants underpaid royalties on natural gas and natural gas liquids produced on federal and Indian lands through the use of below-market prices, improper deductions, improper measurement techniques and transactions with affiliated companies. The United States has filed an intervention in these cases as to some of the defendants, including BROG.

In July 2000, the United States District Court for the District of New Mexico unsealed and BROG was served with the petition in *United States of America ex rel. Mark A. Perry v. BROG Resources, Inc., et al.*, Civil Action No. 9:00CV197, in the United States District Court for the District of New Mexico, wherein plaintiff alleges violations of the civil False Claims Act. The plaintiff claims that BROG understated the value of natural gas and natural gas liquids produced on federal and Indian lands in connection with its computation and reporting of royalty payments. The United States has elected to intervene in this case, but a complaint has not been served upon BROG.

In October 2000, the federal Judicial Panel on Multidistrict Litigation ordered that the *Wright and Osterhoudt* lawsuits be transferred to the United State District Court for the District of Wyoming for inclusion with the Grynberg lawsuit described above in multidistrict litigation proceedings. A similar order was issued in December 2000 transferring the Perry lawsuit. These cases have been consolidated for pre-trial proceedings in the matter styled *In re Natural Gas Royalties Qui Tam Litigation,* MDL-1293, United States District Court for the District of Wyoming.

If successful, this litigation could result in a decrease in royalty income received by the Trust. At this time, no estimate can be made as to the amount of any potential loss in this litigation, or the portion of any such potential loss that would be allocated to the Trust's interest. Any proposed allocation of loss to the Trust will be reviewed by the Trust's consultants.

Quinque Litigation

In September 1999, BROG was served with a class action petition styled *Quinque Operating Company on behalf of Gas Producers v. Gas Pipelines, et al.*, Case No. 99 C 30, in the District Court of Stevens County, Kansas, naming certain of its current or former affiliates as defendants, along with hundreds of other gas production and gas pipeline companies. On February 21, 2002, the District Court granted leave for plaintiffs to file a third amended class action petition substituting in new class representative plaintiffs thereby changing the style of the case to *Will Price, Stixon Petroleum, Inc. and Thomas F. Boles on behalf of Gas Producers v. Gas Pipelines, et al.*, Case No. 99 C 30, in the District Court of Stevens County, Kansas. The petition alleges that the defendants engaged in the mismeasurement of volumes and wrongful analysis of heating content of natural gas and engaged in other activities which resulted in the underpayment of revenue owed to working interest owners, royalty interest owners, overriding royalty interest owners and state taxing authorities. If successful, this litigation could result in a decrease in royalty income received by the Trust. At this time, no estimate can be made as to the amount of any loss in this litigation, or the portion of any such potential loss that would be allocated to the Trust. Any proposed allocation of loss to the Trust will be reviewed by the Trust's consultants.

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, 2002.

PART II

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

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, 2002, is herein incorporated by reference. The Trust has no directors, executive officers or employees. Accordingly, the Trust does not maintain any equity compensation plans and there are no Units reserved for issuance under any such plans.

Item 6. *Selected Financial Data*

	For the Year Ended December 31				
	2002	2001	2000	1999	1998
Royalty income	$38,053,281	$81,368,723	$60,044,773	$32,626,966	$30,317,860
Distributable income	36,417,967	80,126,202	59,188,932	31,795,667	29,498,402
Distributable income per Unit	0.781354	1.719123	1.269909	0.682182	0.635039
Distributions per Unit	0.781354	1.719123	1.269909	0.682182	0.635039
Total assets, December 31	37,972,696	38,051,369	47,659,746	49,048,652	53,753,582

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

The "Description of the Properties," "Trustee's Discussion and Analysis" and "Results of the 4th Quarters of 2002 and 2001" at pages 5 through 9 of the Trust's Annual Report to security holders for the year ended December 31, 2002, are herein incorporated by reference.

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

The Trust invests in no derivative financial instruments, and has no foreign operations or long-term debt instruments. 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 does not market the Trust gas, oil and/or natural gas liquids. BROG is responsible for such marketing.

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

The Financial Statements of the Trust and the notes thereto at page 10 et seq., of the Trust's Annual Report to security holders for the year ended December 31, 2002, are herein incorporated by reference.

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

See information contained in the Trust's Form 8-K, dated July 17, 2001, reporting a change in accountants.

PART III

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

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.

Item 11. ***Executive Compensation***

The Trust has no directors, executive officers or employees. Accordingly, the Trust does not maintain any equity compensation plans and there are no Units reserved for issuance under any such plans.

During the year ended December 31, 2002, the Trustee received total remuneration as follows:

Name of Individual or Number of Persons in Group	Capacities in Which Served	Cash Compensation
Bank One, N.A.(1)	Trustee	$148,399(3)
TexasBank(2)	Trustee	$ 44,316(3)

(1) During 2002, Bank One, N.A. served as Trustee for the period January 1, 2002 through September 30, 2002.

(2) During 2002, TexasBank served as Trustee for the period September 30, 2002 to December 31, 2002.

(3) Under the Trust Indenture, the Trustee is entitled to an administrative fee for its administrative services and the preparation of quarterly and annual statements of: (i) 1/20 of 1% of the first $100 million of the annual gross revenue of the Trust, and 1/30 of 1% of the annual gross revenue of the Trust in excess of $100 million and (ii) the Trustee's standard hourly rates for time in excess of 300 hours annually. Beginning January 1, 2003, in no case will the administrative fee due under items (i) and (ii) above be less than $36,000 per year (as adjusted annually to reflect the increase (if any) in the Producers Price Index as published by the U.S. Department of Labor, Bureau of Labor Statistics).

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

(a) *Security Ownership of Certain Beneficial Owners.* The following table sets forth, as of March 23, 2003, information with respect to each person known to own beneficially more than 5% of the outstanding Units of the Trust:

Name and Address	Amount and Nature of Beneficial Ownership	Percent of Class
Alpine Capital, L.P.(1) 201 Main Street, Suite 3100 Fort Worth, Texas 76102	10,599,200 Units	22.7%
Societe General Asset Management Corp.(2) 1221 Avenue of the Americas New York, New York 10020	5,180,000 Units	11.1%
Capital Group International, Inc.(3) Capital Guardian Trust Company 11100 Santa Monica Blvd Los Angeles, CA 90025	3,040,770 Units	6.5%
McMorgan and Company(4) 1 Bush Street, Suite 800 San Francisco, CA 94104	3,000,000 Units	6.4%

(1) This information was provided to the Trust on Amendment Number 29 to Schedule 13D, dated March 5, 2003, as filed with the SEC by Alpine Capital, L.P. ("Alpine"), which indicated that these Units were beneficially owned by Alpine. Robert W. Bruce, III and Algenpar, Inc., are general partners of Alpine and have shared power to vote and dispose of the Units held by Alpine. The Amendment Number 27 to Schedule 13D may be reviewed for more detailed information concerning the matters summarized herein.

(2) This information was provided to the Trust on Amendment Number 3 to Schedule 13G, dated January 6, 1999, as filed with the SEC. The Amendment Number 3 to Schedule 13G may be reviewed for more detailed information concerning the matters summarized herein.

(3) This information was provided to the Trust in Amendment Number 5 to Schedule 13G dated December 31, 2002. Capital Group International, Inc. and Capital Guardian Trust Company each reported sole voting power over 2,131,440 Units and sole dispositive power over 3,040,770 Units. The Amendment Number 5 to Schedule 13G may be reviewed for more detailed information concerning the matters summarized herein.

(4) This information was provided to the Trust in a Schedule 13G dated July 12, 1999, as filed with the SEC. The Schedule 13G may be reviewed for more detailed information concerning the matters summarized herein.

(b) *Security Ownership of Trustee.* As of December 31, 2002, TexasBank owned no Units.

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 year ended December 31, 2002 and Item 12(b) for information concerning Units owned by TexasBank.

Item 14. ***Controls and Procedures***

The Trust maintains a system of disclosure controls and procedures that is designed to provide reasonable assurance that information required to be disclosed in the Trust's filings under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by BROG to the Trustee and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosure. Due to the pass-through nature of the Trust, BROG provides much of the information disclosed in this Form 10-K/A and the other periodic reports filed by the Trust with the SEC.

The Trustee receives periodic updates from BROG regarding activities related to the Trust. Accordingly, the Trust's ability to timely report certain information required to be disclosed in the Trust's periodic reports is dependent on BROG's timely delivery of such information to the Trust. In order to help ensure the accuracy and completeness of the information required to be disclosed in the Trust's periodic reports, the Trust employs independent public accountants, joint interest auditors, marketing consultants, attorneys and petroleum engineers. These outside professionals assist the Trustee in reviewing and compiling this information for inclusion in this Form 10-K/A and the other periodic reports provided by the Trust to the SEC.

The Trustee has evaluated the Trust's disclosure controls and procedures within the 90 days prior to the filing of this Annual Report on Form 10-K/A and has determined that, subject to BROG's delivery of timely and accurate information to the Trust, such disclosure controls and procedures are effective. The Trustee has not reviewed the Trust's disclosure controls and procedures in concert with management, a board of directors or an independent audit committee. The Trust does not have, nor does the Trust Indenture provide for, officers, a board of directors or an independent audit committee.

Subsequent to the Trustee's evaluation, there were no significant changes in internal controls or other factors that could significantly affect internal controls, including any corrective actions with regard to significant deficiencies and material weaknesses.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules, and Reports on Form 8-K***

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

Financial Statements

Included in Part II of this Report by reference to the Annual Report of the Trust for the year ended December 31, 2002:

Independent Auditors' Reports

Statements of Assets, Liabilities and Trust Corpus

Statements of Distributable Income

Statements of Changes in Trust Corpus

Notes to Financial Statements

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.

Reports on Form 8-K

On October 1, 2002, the Trust filed a Current Report on Form 8-K, dated September 30, 2002, disclosing under Item 5 that it had issued a press release announcing that at a special meeting the Unit Holders had (a) appointed TexasBank as the successor Trustee of the Trust and (b) approved three separate groups of amendments to the Original Indenture.

Exhibits

Exhibit Number		Number Description
(4) (a)	—	Amended and Restated Royalty Trust Indenture, dated September 30, 2002 (the original Royalty Trust Indenture, dated November 1, 1980 having been entered into between Southland Royalty Company and The Fort Worth National Bank, as Trustee) heretofore filed as Exhibit 99.2 of the Trust's Current Report on Form 8-K filed with the SEC on October 1, 2002, is incorporated herein by reference.*
(b)	—	Net Overriding Royalty Conveyance from Southland Royalty Company to the Forth Worth National Bank, as Trustee, dated November 3, 1980 (without Schedules), heretofore filed as Exhibit 4(b) to the Trust's Annual Report on Form 10-K filed with the SEC for the fiscal year ended December 31, 1980, is incorporated herein by reference.*
(c)	—	Assignment of Net Overriding Interest (San Juan Basin Royalty Trust), dated September 30, 2002, between Bank One, N.A. and TexasBank heretofore filed as Exhibit 4(c) to the Trust's Quarterly Report on Form 10-Q with the SEC for the quarter ended September 30, 2002, is incorporated herein by reference.*
(13)	—	Registrant's Annual Report to security holders for fiscal year ended December 31, 2002, heretofore filed as Exhibit 13 to the Trust's Annual Report on Form 10-K for the fiscal year ended December 31, 2002, and filed with the SEC on March 27, 2003, is incorporated herein by reference.
(23.1)	—	Consent of Cawley, Gillespie & Associates, Inc., reservoir engineer.**

* A copy of this Exhibit is available to any Unit Holder (free of charge) upon written request to the Trustee, TexasBank, 2525 Ridgmar Boulevard, Suite 100, Fort Worth, Texas 76116.

** 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.

TexasBank, as
Trustee of the San Juan Basin
Royalty Trust

/s/ Lee Ann Anderson

Lee Ann Anderson
Vice President and Trust Officer

Date: April 1, 2003

(The Trust has no directors or executive officers)

CERTIFICATION

I, Lee Ann Anderson, certify that:

1. I have reviewed this annual report on Form 10-K/A of San Juan Basin Royalty Trust, for which TexasBank acts as Trustee;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, distributable income and changes in trust corpus of the registrant as of, and for, the period presented in this annual report;

4. I am responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14), or for causing such procedures to be established and maintained, for the registrant and I have:

a) designed such disclosure controls and procedures, or caused such controls and procedures to be designed, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to me by others within those entities, particularly during the period in which this annual report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the "Evaluation Date"); and

c) presented in this annual report my conclusions about the effectiveness of the disclosure controls and procedures based on my evaluation as of the Evaluation Date;

5. I have disclosed, based on my most recent evaluation, to the registrant's auditors:

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves persons who have a significant role in the registrant's internal controls; and

6. I have indicated in this annual report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of my most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

In giving the certifications in paragraphs 4, 5 and 6 above, I have relied to the extent I consider reasonable on information provided to me by Burlington Resources Oil & Gas Company LP.

TexasBank, as Trustee for the
San Juan Basin Royalty Trust

By: /s/ Lee Ann Anderson

Lee Ann Anderson
Vice President and Trust Officer

Date: April 1, 2003

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