SAN JUAN BASIN ROYALTY TRUST
Form 10-K405
April 01, 2002

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2001,

or

o **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 San Juan Basin Royalty Trust Indenture)

Texas *(State or other jurisdiction of incorporation or organization)*	**75-6279898** *(I.R.S. Employer Identification Number)*
Bank One, N.A. **Corporate Trust Department** **P.O. Box 2604** **Fort Worth, Texas** *(Address of principal executive officers)*	**76113** *(Zip Code)*

(817) 884-4630

(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 þ No o

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

At March 28, 2002, there were 46,608,796 Units of Beneficial Interest of the Trust outstanding with an aggregate market value on that date of $554,644,672.

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 and 8; Results of the 4th Quarters of 2001 and 2000 at page 9; 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 10 et seq., in registran Annual Report to Unit holders for fiscal year ended December 31, 2001 are incorporated herein by reference for Item 2 (Properties), Item 3 (Legal Proceedings), 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.

TABLE OF CONTENTS

Table of Contents

PART I

Item 1. ***Business***

The San Juan Basin Royalty Trust (the Trust) is an express trust created under the laws of the state of Texas by the San Juan Basin Royalty Trust Indenture (the Trust Indenture) entered into on November 3, 1980, between Southland Royalty Company (Southland Royalty) and The Fort Worth National Bank, a banking association organized under the laws of the United States, as Trustee. The Trustee is now Bank One, N.A. The principal office of the Trust (sometimes referred to herein as the Registrant) is located at 500 Throckmorton Street, Fort Worth, Texas 76102, Attention: Corporate Trust Department (telephone number (817) 884-4630).

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 in the San Juan Basin of northwestern New Mexico. The conveyance of this 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.

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, El Paso Natural Gas Company, Meridian Oil, Inc. (MOI) and Meridian Oil Trading Inc. also became indirect subsidiaries 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 and MOI survived and succeeded to the ownership of all of the assets, has the rights, powers and privileges and assumed all of the liabilities and obligations of Southland Royalty. Subsequent to the merger, MOI changed its name to Burlington Resources Oil & Gas Company LP (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 interests from which the Royalty was carved) from the sale of the production attributable to the interests in properties from which the Royalty was carved (the Underlying Properties), 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

Table of Contents

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 Properties 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) net revenues from the Trust properties, plus any decrease in cash reserves previously established for contingent liabilities and any other cash receipts of the Trust over (ii) the expenses and payments of liabilities of the Trust plus any net increase in cash reserves for contingent liabilities.

Cash 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, or certificates of deposit of banks having capital, surplus and undivided profits in excess of $50,000,000, 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 75% net overriding royalty conveyed to the Trust was carved out the Underlying Properties, which consist of Southland Royalty s (now BROG s) working interests and royalty interests in 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.

Table of Contents

Producing Acreage, Wells and Drilling

The Underlying Properties consist of working interests and royalty interests 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, the Trust properties contain 3,305 gross (976 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, 2001, 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.

BROG revised its 2001 capital budget estimate for the Underlying Properties upward from $30.2 million to $38.8 million. BROG s capital plan for the Underlying Properties for 2001 estimated 406 projects, including the drilling of 49 new wells operated by BROG. In 2001, BROG actually participated in 663 projects, including 61 new wells operated by BROG. BROG informed the Trust that the upward revision was due to the fact that service costs had been expected to increase approximately 10% in 2001 as compared to the prior year. However, BROG indicates that as a result of higher commodity prices in 2001 and a resulting increased demand for equipment and services, some costs actually increased in 2001 by as much as 40%. In addition, the Bureau of Land Management has undertaken an environmental impact study of the entire San Juan Basin such that new drilling activity located more than 300 feet from an existing road now requires an additional level of regulatory approval on a well-by-well basis. More regulatory approvals to drill were obtained in 2001 than expected, which resulted in an increase in drilling activity.

The aggregate capital expenditures reported by BROG in calculating distributable income for 2001 include approximately $9,250,000 attributable to the capital budgets for 1999 and 2000. 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 $27 million for 2001 budgeted projects were used in calculating distributable income in calendar year 2001, and approximately $7 million in capital expenditures have been used in calculating distributions for the first two months of 2002. Therefore, an additional approximately $4.8 million in capital expenditures for 2001 projects remains to be spent.

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 well 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 six gross (.29 net) miscellaneous coal seam capital projects in progress as of December 31, 2001.

During 2000, in calculating the net proceeds to the Trust, BROG deducted approximately $25.6 million of capital expenditures for projects, including drilling and completion of 45 gross (25.45 net) conventional wells, recompletion of 15 gross (6.80 net) conventional wells, 12 gross (6.75 net) coal seam wells, 4 gross (.17 net) coal seam well recompletions, 41 gross (.24 net) coal seam recavitations, and facilities maintenance.

Table of Contents

There were 124 gross (36.15 net) new conventional wells, 59 gross (21.37 net) conventional well recompletions, 10 gross (2.14 net) coal seam wells, 12 gross (1.64 net) coal seam recompletions, and 4 gross (.03 net) coal seam recavitations in progress as of December 31, 2000.

BROG has informed the Trust that it has reduced its projections for capital expenditures for the Underlying Properties for 2002 from an estimated $17.1 million to an estimated $12.4 million. BROG anticipates the drilling of 43 new wells to be operated by BROG and 26 wells to be operated by third parties. Of the new BROG operated wells, 36 are projected to be conventional wells completed to the Pictured Cliffs, Mesaverde, and/or Dakota formations, and the remaining seven are projected as coal seam gas wells to be completed in the Fruitland Coal formation. BROG projects approximately $9.6 million to be spent on the new wells, and $2.8 million to be expended in working over existing wells and in the maintenance and improvement of production facilities.

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. Eighty-acre spacing has been permitted in the Mesaverde formation since 1997. The Mesaverde formation was originally developed in the 1950 s on 320-acre spacing, with infill drilling initiated in the early 1970 s on 160-acre spacing. In 1994, BROG undertook an extensive study of the Mesaverde formation. Results indicated that downspaced drilling (infill drilling) on 80-acre spacing could significantly increase recoverable gas reserves in this reservoir. A pilot program began in 1997 and was expanded in 1998 to include two additional areas.

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 2001 averaged approximately 121 MMcf per day, as compared to average production of approximately 116 MMcf per day for calendar 2000 and 113 MMcf per day for calendar 1999.

BROG indicates its budget for 2002 reflects continued, significant development of properties in which the Trust s net overriding royalty interest is relatively high, as well as 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 distribution is received. Production of oil and gas and related average sales prices attributable to the Royalty for the three years ended December 31, 2001 were as follows:

	2001		**2000**		**1999**	
	Oil (Bbls)	**Gas (Mcf)**	**Oil (Bbls)**	**Gas (Mcf)**	**Oil (Bbls)**	**Gas (Mcf)**
Production	42,056	19,272,021	47,441	20,317,750	35,341	19,527,666
Average Price	$ 24.99	$ 4.61	$ 24.66	$ 2.99	$ 14.41	$ 1.78

Pricing Information

Gas produced in the San Juan Basin is sold in both interstate and intrastate commerce. Reference is made to 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 42,960,149 Mcf during 2001.

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, except for a pre-existing contract which has since expired, 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. 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 securityholders for the year ended December 31, 2001 for further discussion of this settlement and its impact on the Trust.

BROG entered into a contract dated November 10, 1999, as amended, for the sale of all volumes of Trust gas to Duke Energy and Marketing, L.L.C. (Duke). That contract, as amended, provides for delivery of gas at various delivery points over a period commencing January 1, 2000 and ending March 31, 2002 and provides for 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. BROG has distributed requests for proposal to 27 potential bidders with a view toward selecting one or more contracts for the sale of Trust gas for the period commencing April 1, 2002, through March 31, 2004.

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 Securities and Exchange Commission (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.

Table of Contents

The independent petroleum engineers reports as to the proved oil and gas reserves as of December 31, 1999, 2000 and 2001 were prepared by Cawley, Gillespie & Associates, Inc. The following table presents a reconciliation of proved reserve quantities attributable to the Royalty from December 31, 1998 to December 31, 2001 (in thousands):

	Crude Oil (Bbls)	Natural Gas (Mcf)
Reserves as of December 31, 1998	333	163,431
Revisions of previous estimates	120	53,936
Extensions, discoveries and other additions	29	14,498
Production	(32)	(17,650)
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

Estimated quantities of proved developed reserves of crude oil and natural gas as of December 31, 2001, 2000 and 1999 were as follows (in thousands):

	Crude Oil (Bbls)	Natural Gas (Mcf)
2001	356	162,577
2000	624	277,459
1999	422	201,891

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.

6

Table of Contents

The 2001, 2000 and 1999 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):

	2001	2000	1999
Balance, January 1	$ 818,212	$229,721	$144,472
Revisions of prior-year estimates, change in prices and other	(652,337)	530,811	90,172
Extensions, discoveries and other additions	7,519	94,753	13,257
Accretion of discount	81,821	22,972	14,447
Royalty income	(81,369)	(60,045)	(32,627)
Balance, December 31	$ 173,846	$818,212	$229,721

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 $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 upward revision in reserve quantities for 2000 as compared to 1999 was primarily due to significantly higher gas prices in December 2000.

December average prices of $2.39 per Mcf of conventional gas, $1.49 per Mcf of coal seam gas and $22.30 per Bbl of oil were used at December 31, 1999, 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, 2001, 2000 and 1999 (in thousands except amounts per Unit):

	2001		2000		1999	
	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	$290,582	$173,846	$1,580,837	$818,212	$408,609	$229,721
Proved Developed	$266,834	$164,164	$1,445,557	$752,825	$383,356	$219,677
Total Proved Per Unit	$ 6.23	$ 3.73	$ 33.92	$ 17.55	$ 8.77	$ 4.93

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.

The ability to transport and sell oil and natural gas 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. For 2000, this tax credit was $1.06 per MMBtu. For 2001, the amount of the credit will be determined by the Treasury Department no later than April 1, 2002, and, based on historical trends, is expected to approximate (within a 2-3% range) the 2000 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 coal seam volumes produced from Trust 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.

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

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 alleges that additional royalties are due on production from federal and Indian leases in the State of New Mexico on properties that are 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 Trust. BROG has indicated it will provide information identifying the Underlying Properties affected by the settlement, the Trust s share of the settlement, and the manner and timing of deductions from upcoming distribution(s) from the Trust. The Trust s legal and joint interest auditing consultants will review the information to be provided and advise the Trust as to the appropriateness of any such deductions.

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. BROG indicates that the volume adjustment commenced in August 2000. The Trust s consultants continue to monitor those adjustments.

Table of Contents

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.

1. *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, the 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 Coal Bed Methane administrative appeals, to the claims in the suits in the In re Natural Gas Royalties qui tam litigation described below, the administrative appeals have been stayed by agreement with MMS pending the resolution of the gas qui tam litigation, and 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.

2. *Jicarilla Indian Tribe Proceedings.*

This appeal arises from a MMS Order to Perform dated June 10, 1998. The Order to Perform states that, in valuing production for royalty purposes, BROG must perform (i) 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) and (ii) 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). BROG currently performs dual accounting calculations on Indian leases, but the Order alleges that its dual accounting calculations are based on less than major portion prices. 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.

In December 2000, BROG and the Tribe entered into a settlement resolving the issues associated with the dual accounting calculation. The total settlement amount was $3,260,366. BROG is currently determining what portion of this dual accounting settlement will be allocated to the Trust. Any such allocation will be reviewed by the Trust s consultants. The major portion calculation issue remains outstanding.

Litigation

1. *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 in paragraph 2 below.

2. *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 States District Court for the District of Wyoming for inclusion with the Grynberg lawsuit described in paragraph 1 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

Table of Contents

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.

3. *Quinque Litigation.*

In September 1999, BROG was served with a class action petition styled Quinque Operating Burlington 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. 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, 2001.

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, 2001, is herein incorporated by reference.

Item 6. ***Selected Financial Data***

	For the Year Ended December 31				
	2001	2000	1999	1998	1997
Royalty income	$81,368,723	$60,044,773	$32,626,966	$30,317,860	$49,497,479
Distributable income	80,126,202	59,188,932	31,795,667	29,498,402	48,648,930
Distributable income per Unit	1.719123	1.269909	0.682182	0.635039	1.043770
Distributions per Unit	1.719123	1.269909	0.682182	0.635039	1.043770
Total assets, December 31	38,051,369	47,659,746	49,048,652	53,753,582	61,231,280

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

The Trustee s Discussion and Analysis and Results of the 4th Quarters of 2001 and 2000 at pages 7 through 9 of the Trust s Annual Report to securityholders for the year ended December 31, 2001, are herein incorporated by reference.

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

The Trust has not entered into derivative financial instruments, derivative commodity instruments or other similar instruments during 2001. As discussed in Item 2. Properties Pricing Information, 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, 2001, are herein incorporated by reference.

Table of Contents

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 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 or executive officers. During the year ended December 31, 2001, 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.	Trustee	$125,259.37(1)

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

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

(a) *Security Ownership of Certain Beneficial Owners.* The following table sets forth, as of December 31, 2001, 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)	12,585,900 Units	27.0%
201 Main Street, Suite 3100		
Fort Worth, Texas 76102		
Societe General Asset Management Corp.(2)	5,180,000 Units	11.1%
1221 Avenue of the Americas		
New York, New York 10020		
McMorgan and Company(3)	3,000,000 Units	6.4%
1 Bush Street, Suite 800		
San Francisco, CA 94104		
Capital Group International, Inc.(4)	2,400,000 Units	5.2%
Capital Guardian Trust Company		
11100 Santa Monica Blvd.		
Los Angeles, CA 90025		

(1) This information was provided to the Trust on Amendment Number 24 to Schedule 13D, dated March 15, 2002, as filed with the Securities and Exchange Commission (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 24 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 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.

(4) This information was provided to the Trust in Amendment Number 4 to Schedule 13G dated December 31, 2001. Capital Group International, Inc. and Capital Guardian Trust Company each reported sole voting power over 1,853,600 Units and sole dispositive power over 2,400,000 Units. The Amendment Number 4 to Schedule 13G may be reviewed for more detailed information concerning the matters summarized herein.

(b) *Security Ownership of Management.* In various fiduciary capacities, Bank One, N.A. owned, as of December 31, 2001, an aggregate of 37,252 Units with no right to vote any of these Units. Bank One, N.A. disclaims any beneficial interest in these Units. The number of Units reflected in this paragraph includes Units held by all branches of Bank One, N.A.

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, 2001 and Item 12(b) for information concerning Units owned by Bank One, N.A. in various fiduciary capacities.

PART IV

Item 14. ***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, 2001:

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.

Exhibits

Exhibit Number	Number Description
(4)(a)	San Juan Basin Royalty Trust Indenture, dated November 3, 1980, between Southland Royalty Company and The Fort Worth National Bank (now Bank One, N.A.), as Trustee, heretofore filed as Exhibit 4(a) to the Trust s Annual Report on Form 10-K to the SEC for the fiscal year ended December 31, 1980, is incorporated herein by reference.*
(b)	Net Overriding Royalty Conveyance from Southland Royalty Company to the Forth Worth National Bank (now Bank One, N.A.), as Trustee, dated November 3, 1980 (without Schedules), heretofore filed as Exhibit 4(b) to the Trust s Annual Report on Form 10-K to the SEC for the fiscal year ended December 31, 1980, is incorporated herein by reference.*
(13)	Registrant s Annual Report to security holders for fiscal year ended December 31, 2001.**
(23.1)	Consent of Cawley, Gillespie & Associates, Inc., reservoir engineer.**

* A copy of this Exhibit is available to any Unit holder, at the actual cost of reproduction, upon written request to the Trustee, Bank One, N.A., P.O. Box 2604, Fort Worth, Texas 76113.

** Filed herewith.

Reports on Form 8-K

None.

Table of Contents

SIGNATURE

Pursuant to the Requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BANK ONE, N.A.
TRUSTEE OF THE SAN JUAN BASIN ROYALTY TRUST

/s/ LEE ANN ANDERSON

Lee Ann Anderson
Vice President

Date: April 1, 2002

(The Trust has no directors or executive officers)

16

Table of Contents

EXHIBIT INDEX

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