SAN JUAN BASIN ROYALTY TRUST
Form 10-K
March 01, 2013

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

x **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the Fiscal Year Ended December 31, 2012

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 No. 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.)*

Compass Bank

300 W. 7th Street, Suite B

Fort Worth, Texas	**76102**
(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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

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

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 x 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. x

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

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

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

State the aggregate market value of the Units of Beneficial Interest held by non-affiliates of the registrant as of June 30, 2012: $698,653,485.

At March 1, 2013, there were 46,608,796 Units of Beneficial Interest of the Trust outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Units of Beneficial Interest and Description of the Properties , in registrant s Annual Report to Unit Holders for the year ended December 31, 2012, are incorporated herein by reference for Item 5 (Market for Registrant s Units, Related Unit Holder Matters and Issuer Purchases of Units) and Item 7 (Trustee s Discussion and Analysis of Financial Condition and Results of Operation) of Part II of this Report.

PART I

Certain information included in this Annual Report on Form 10-K 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, estimated future net revenues, estimates of reserves, the results of the Trust s activities, and regulatory matters. Such forward-looking statements generally are accompanied by words such as may, will, estimate, expect, predict, project, anticipate, goal, should, assume, believe, words that convey the uncertainty of future events or outcomes. Such statements reflect Burlington Resources Oil & Gas Company LP s (Burlington), 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 Compass Bank, the Trustee (herein so called) of the Trust, and Burlington and involve risks and uncertainties. These risks and uncertainties include volatility of oil and gas prices, product supply and demand, competition, regulation or government action, litigation and uncertainties about estimates of reserves. 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) 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 First Restated Indenture) and, effective as of December 12, 2007, the First Restated Indenture was amended and restated (the First Restated Indenture, as amended and restated, the Indenture). The Trustee of the Trust is Compass Bank (as a result of the merger discussed below). The principal office of the Trust is located at 300 West 7th Street, Suite B, Fort Worth, Texas 76102 (toll-free 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) through its website as soon as reasonably practicable after electronically filing or furnishing such material with or to the SEC. The Trust s materials filed with the SEC are available at the SEC s Public Reference Room at 100 F Street, NE, Washington, DC 20549 or by calling the Public Reference Room of the SEC at 1-800-SEC-0330. The SEC also maintains the internet site of http://www.sec.gov. This site contains reports and, as applicable, proxy and information statements, and other information regarding the Trust and other issuers that file electronically with the SEC.

Pursuant to the Net Overriding Royalty Conveyance (the Conveyance) effective November 1, 1980, Southland conveyed to the Trust a 75% net overriding royalty interest (the Royalty). The Royalty is similar to a net profits interest and it burdens certain of Southland s oil and gas leasehold interests (the Underlying Properties) in properties located in the San Juan Basin of northwestern New Mexico, all as more particularly described in the Conveyance and under Item 2. Properties herein.

As a result of a merger on March 24, 2006, Compass Bank succeeded TexasBank as Trustee of the Trust. On September 7, 2007, Compass Bank s parent company, Compass Bancshares, Inc., was acquired by and is now a wholly-owned subsidiary of Banco Bilbao Vizcaya Argentaria, S.A.

The Royalty constitutes the principal asset of the Trust. 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 outstanding as of the close of business on November 3, 1980. Each stockholder of Southland of record at the close of business on November 3, 1980 received one freely tradable Unit for each share of the common stock of Southland then held. Holders of Units are referred to herein as Unit Holders. Subsequent to the Conveyance of the Royalty, through a series of assignments and mergers, Southland s successor became Burlington. On March 31, 2006, a subsidiary of ConocoPhillips completed its acquisition of Burlington Resources, Inc., Burlington s parent. As a result, ConocoPhillips became the parent of Burlington Resources, Inc., which in turn, is the parent of Burlington.

The function of the Trustee is to collect the net proceeds attributable to the Royalty (Royalty Income), to pay all expenses and charges of the Trust and distribute the remaining available income to the Unit Holders. The Trust does not operate the Underlying Properties and, in fact, is not empowered to carry on any business activity. The Trust has no employees, officers or directors. All administrative functions of the Trust are performed by the Trustee.

Burlington is the principal operator of the Underlying Properties. A very high percentage of the Royalty Income is attributable to the production and sale by Burlington of natural gas from the Underlying Properties. Accordingly, the market price for natural gas produced and sold from the San Juan Basin heavily influences the amount of Royalty Income distributed by the Trust and, by extension, the price of the Units.

The Trust is a widely held fixed investment trust (WHFIT) classified as a non-mortgage widely held fixed investment trust (NMWHFIT) for federal income tax purposes. The Trustee, 300 West 7th Street, Suite B, Fort Worth, Texas 76102 (toll-free telephone number (866) 809-4553, email address: *sjt@bbvacompass.com*), is the representative of the Trust that will provide tax information in accordance with the applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT and a NMWHFIT. The tax information is generally posted by the Trustee at *www.sjbrt.com*.

The Trust received approximately $34.5 million, $68 million, and $80 million in Royalty Income from Burlington in each of the fiscal years ended December 31, 2012, 2011, and 2010, respectively. After deducting administrative expenses and accounting for interest income and any change in cash reserves, the Trust distributed approximately $33.5 million, $67.2 million, and $78.4 million, to Unit Holders in each of the fiscal years ended December 31, 2012, 2011, and 2010, respectively. The Trust s corpus was approximately $12.2 million, $13.1 million, and $14.7 million, as of December 31, 2012, 2011, and 2010, respectively.

The term net proceeds, as used in the Conveyance, means the excess of gross proceeds received by Burlington during a particular period over production costs for such period. Gross proceeds means the amount received by Burlington (or any subsequent owner of the Underlying Properties) from the sale of the production attributable to the Underlying Properties subject to certain adjustments. Production costs generally means costs incurred on an accrual basis by Burlington in operating the Underlying Properties, 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 the Underlying Properties 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.

Compliance with state and federal environmental protection laws could reduce the Royalty Income received by the Trust. Costs of complying with such laws and regulations affect the production costs incurred by Burlington in operating the Underlying Properties and may also affect capital expenditures by Burlington. The Trust has no information regarding any estimated capital expenditures by Burlington specifically allocable to environmental control facilities in the current or succeeding fiscal years.

Certain of the Underlying Properties are operated by Burlington with the obligation to conduct its operations in accordance with reasonable and prudent business judgment and good oil and gas field practices. As operator, Burlington 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. Burlington also is responsible, subject to the terms of an 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. Additionally, Burlington has the obligation to maintain books and records sufficient to determine the amounts payable to the Trustee.

Proceeds from production in the first month are generally received by Burlington in the second month, the net proceeds attributable to the Royalty are paid by Burlington to the Trustee in the third month, and distribution by the Trustee to the Unit Holders is made in the fourth month. Unit Holders of record as of the last business day of each month (the monthly record date) will be entitled to receive the calculated monthly distribution amount for such month on or before ten business days after the monthly record date. The amount of each monthly distribution will generally be determined and announced ten days before 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 may be 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 at least AAm by Standard & Poor s and at least Aa by Moody s, subject, in each case, to certain other qualifying conditions. Currently, such funds are placed in interest-bearing negotiable order of withdrawal accounts whose funds are either insured by the Federal Deposit Insurance Corporation or secured by other assets of BBVA Compass Bank.

The Underlying Properties are primarily gas producing properties. Normally there is greater demand for gas used for heating or air conditioning purposes in the summer and winter months than during the rest of the year. Otherwise, the Royalty Income is not subject to seasonal factors or in any manner related to or dependent upon patents, licenses, franchises or concessions. The Trust conducts no research activities.

The exploration for and the production of gas and oil is a speculative business. The Trust has no means of ensuring continued income from the Royalty at the present level or otherwise. In addition, fluctuations in prices and supplies of gas and oil and the effect these fluctuations might have on Royalty Income to the Trust and on reserves net to the Trust cannot be accurately projected. The Trustee has no information with which to make any projections beyond information on economic conditions that is generally available to the public and thus is unwilling to make any such projections.

ITEM 1A. ***RISK FACTORS***

Although risk factors are described elsewhere in this Annual Report on Form 10-K, the following is a summary of the principal risks associated with an investment in Units of the Trust.

Oil and gas prices fluctuate due to a number of factors, and lower prices will reduce net proceeds to the Trust and distributions to Unit Holders.

The Trust s monthly distributions are highly dependent upon the prices realized from the sale of gas and, to a lesser extent, oil. Oil and gas prices can fluctuate widely in response to a variety of factors that are beyond the control of the Trust and Burlington. Factors that contribute to price fluctuation include, among others:

- political conditions worldwide, in particular political disruption, war or other armed conflicts in oil producing regions;
- worldwide economic conditions;
- weather conditions;

- the supply and price of foreign oil and gas, including liquefied natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities; and
- the effect of worldwide energy conservation and climate change measures.

Moreover, government regulations, such as regulation of natural gas transportation and price controls, can affect product prices in the long term.

Lower oil and gas prices may reduce the amount of oil and gas that is economic to produce and reduce net profits to the Trust. The volatility of energy prices reduces the predictability of future cash distributions to Unit Holders.

Increased costs of production and development will result in decreased Trust distributions.

Production and development costs attributable to the Underlying Properties are deducted in the calculation of net proceeds. Accordingly, higher production and development costs, without concurrent increases in revenues, decrease the share of net proceeds paid to the Trust as Royalty Income.

If development and production costs of the Underlying Properties exceed the proceeds of production from the Underlying Properties, such excess costs are carried forward and the Trust will not receive a share of net proceeds for the Underlying Properties until future net proceeds from production from such properties exceed the total of the excess costs. Development activities may not generate sufficient additional revenue to repay the costs; however, the Trust is not obligated to repay the excess costs except through future production.

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

The value of the Units of the Trust depends upon, among other things, the amount of reserves attributable to the Royalty and the estimated future value of the reserves. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the Underlying Properties will vary from estimates and those variations could be material. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation; and
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures.

Changes in these assumptions can materially change reserve estimates. The reserve data included herein are estimates only and are subject to many uncertainties. Actual quantities of oil and natural gas may differ considerably from the amounts set forth herein. In addition, different reserve engineers may make different estimates of reserve quantities and cash flows based upon the same available data.

The operators of the Underlying Properties are subject to extensive governmental regulation.

Oil and gas operations have been, and in the future will be, affected by federal, state and local laws and regulations and other political developments, such as price or gathering rate controls and environmental protection regulations. Also, climate change laws and regulations may, in the future, have an increasing impact on oil and natural gas production, gathering, marketing and transportation.

Operating risks for Burlington and other operators of the Underlying Properties can adversely affect Trust distributions.

Royalty Income payable to the Trust is derived from the sale of natural gas and oil production following the gathering and processing of those minerals, which operations are subject to risk inherent in such activities, such as blowouts, cratering, explosions, uncontrollable flows of oil, gas or well fluids, fires, pollution and other environmental risks and litigation concerning routine and extraordinary business activities and events. These risks could result in substantial losses which are deducted in calculating the net proceeds paid to the Trust due to injury and loss of life, severe damage to and destruction of property and equipment, pollution and other environmental damage and suspension of operations.

None of the Trustee, the Trust nor the Unit Holders control the operation or development of the Underlying Properties.

Neither the Trustee nor the Unit Holders can influence or control the operation or future development of the Underlying Properties. The Underlying Properties are owned by Burlington and Burlington operates the majority of such properties and handles the calculation of the net proceeds attributable to the Royalty and the payment of Royalty Income to the Trust.

The Royalty can be sold and the Trust can be terminated in certain circumstances.

The Trust will be terminated and the Trustee must sell the Royalty if holders of at least 75% of the Units approve the sale or vote to terminate the Trust, or if the Trust s gross revenue for each of two successive years is less than $1,000,000 per year. Following any such termination and liquidation, the net proceeds of any sale will be distributed to the Unit Holders and Unit Holders will receive no further distributions from the Trust. We cannot assure you that any such sale will be on terms acceptable to all Unit Holders.

Mineral properties, such as the Underlying Properties, are depleting assets and, if Burlington or other operators of the Underlying Properties do not perform additional development projects, the assets may deplete faster than expected.

The Royalty Income payable to the Trust is derived from the sale of depleting assets. Accordingly, the portion of the distributions to Unit Holders (to the extent of depletion taken) may be considered a return of capital. The reduction in proved reserve quantities is a common measure of depletion. Future maintenance and development projects on the Underlying Properties will affect the quantity of proved reserves. The timing and size of these projects will depend on the market prices of natural gas. If Burlington does not implement additional maintenance and development projects, the future rate of production decline of proved reserves may be higher than the rate currently expected by the Trust.

Unit Holders have limited voting rights.

Voting rights as a Unit Holder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Unit Holders or for an annual or other periodic re-election of the Trustee. Unlike corporations, which are generally governed by boards of directors elected by their equity holders, the Trust is administered by a corporate trustee in accordance with the Indenture and other organizational documents. The Trustee has extremely limited discretion in its administration of the Trust.

ITEM 1B. *UNRESOLVED STAFF COMMENTS*

During the 180-day period before the end of the Trust s fiscal year to which this Annual Report on Form 10-K relates, the Trust did not receive any written comments from the SEC staff regarding its periodic or current reports under the Securities Exchange Act of 1934 that remain unresolved.

ITEM 2. ***PROPERTIES***

The Royalty conveyed to the Trust was carved out of Southland s (now Burlington s) working interests and royalty interests in certain properties situated in the San Juan Basin in northwestern New Mexico. See Item 1. Business for information on the conveyance of the Royalty to the Trust. 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 Burlington (from which the Royalty was carved) in such wells and acres.

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

Producing Acreage, Wells and Drilling

The Underlying Properties 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 and 4,015 gross (1,158.5 net) wells, calculated on a well bore basis and not including multiple completions as separate wells. Of those wells, 7 gross (5.5 net) are oil wells and the balance are gas wells. Burlington reports that approximately 839 gross (319.6 net) of the wells are multiple completion wells resulting in a total of 4,854 gross (1,478.1 net) completions. The Trust has inquired of Burlington whether the acreage is developed or undeveloped. Burlington has informed the Trust that all of the subject acreage is held by production, and even though it has not been fully developed in every formation, Burlington has classified all of such acreage as developed. Production from conventional gas wells is primarily from the Pictured Cliffs, Mesaverde and Dakota formations. During 1988, Southland began development of coal seam reserves in the Fruitland Coal formation. In 2011 Burlington drilled a well which was completed not only to the Mesaverde and the Dakota formations, but also to the Mancos Shale formation which lies between the two. Burlington indicates it will continue to study the Mancos Shale formation and to drill wells intended to be completed to all three of the Mesaverde, Dakota and Mancos Shale formations. In 2012 Burlington commenced a horizontal well designated the Yert 1-H in the Mancos Shale formation. While Burlington will continue to assess its program of horizontal drilling, horizontal activity in the Mancos Shale is uncertain for 2013.

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 Burlington.

Capital expenses of $22.2 million were included in calculating Royalty Income paid to the Trust in calendar year 2012, and included expenditures for the drilling and completion of 28 gross (7.97 net) conventional wells. There were six gross (4.39 net) conventional wells in progress as of December 31, 2012. The Yert 1-H is an exploratory well. Burlington indicates it expects to have production data on the Yert 1-H by the end of the first quarter of 2013. All of the other wells were development wells. There were no dry exploratory or development wells drilled in 2012.

Approximately $14.1 million of capital expenditures covered 114 projects budgeted for 2012. Approximately $13.2 million of those costs were incurred in drilling 24 new wells commenced in 2012 to be operated by Burlington and none to be operated by third parties. The balance of the expenditures allocable to 2012 projects was attributable to the workover of existing wells and the maintenance and improvement of production facilities.

The $22.2 million of capital expenses reported by Burlington for 2012 included approximately $8.1 million attributable to the capital budgets for prior years. This occurs because capital expenditures are deducted in calculating royalty income in the month they accrue, and projects within a given year s budget often extend into subsequent years. Further, Burlington 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. In addition, with respect to wells not operated by Burlington, Burlington 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.

During 2011, in calculating Royalty Income, Burlington deducted approximately $21 million of capital expenditures for projects, including drilling and completion of 56 gross (12.05 net) conventional wells and five gross (1.04 net) coal seam wells. There were nine gross (1.99 net) conventional wells in progress as of December 31, 2011. All of the wells were development wells and there were no dry development wells drilled in 2011.

During 2010, in calculating Royalty Income, Burlington deducted approximately $13.1 million of capital expenditures for projects, including drilling and completion of 61 gross (8.63 net) conventional wells and six gross (1.65 net) coal seam wells. There were eight gross (0.32 net) conventional wells and two gross (0.07 net) coal seam wells in progress as of December 31, 2010. All of the wells were development wells and there were no dry development wells drilled in 2010.

Burlington has informed the Trust that its budget for capital expenditures for the Underlying Properties in 2013 is estimated at $28.5 million. Of the $28.5 million, approximately $5 million will be attributable to the capital budgets for 2012 and prior years. Burlington reports that based on its actual capital requirements, the pace of regulatory approvals, the mix of projects and swings in the price of natural gas, the actual capital expenditures for 2013 could range from $15 million to $45 million.

Burlington anticipates 412 projects in 2013. Approximately $18.2 million of the $28.5 million budget is allocable to 24 new wells, including 18 wells scheduled to be dually completed in the Mesaverde and Dakota formations and two wells to be completed in all three of the Mesaverde, Mancos Shale and Dakota formations. Approximately $5.4 million will be spent on recompletions and miscellaneous facilities projects. In light of the challenged price environment for natural gas and natural gas liquids, Burlington will increase its recompletion activity in 2013, noting that such activity is intended to open a new zone of production at a substantially lower cost than drilling a new well. Of the $5 million attributable to the budgets for prior years, approximately $3 million is allocable to 30 new wells and the $2 million balance will be applied to miscellaneous capital projects such as workovers and operated facility projects.

In February 2002, Burlington 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 July 2003, the OCD approved 160-acre spacing in the Fruitland Coal formation. Eighty-acre spacing has been permitted in the Mesaverde formation since 1997. The OCD has approved 320-acre spacing units for wells completed to the Mancos Shale within the Basin Mancos Gas Pool. For wells drilled horizontally, multiple units may be combined along the well bore so long as that well bore is perforated in each such unit. The Yert 1-H, for example, has been assigned a unit of 571.72 acres. Burlington reports it anticipates operating three drilling rigs in the San Juan Basin during 2013 and that emphasis will be placed on re-working existing wells.

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. Royalty Income for a calendar year is based on the actual gas and oil production during the period beginning with November of the preceding calendar year through October of the current calendar year. Production of oil and gas and related average sales prices attributable to the Royalty for the three years ended December 31, 2012, were as follows:

	2012		2011		2010	
	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)	Gas (Mcf)	Oil (Bbls)
Production	10,259,791	16,369	15,265,827	26,981	17,102,939	31,808
Average Price	$ 3.56	$ 84.36	$ 4.76	$ 81.08	$ 4.86	$ 67.08

Production volumes and costs attributable to the Underlying Properties for the three years ended December 31, 2012 were as follows:

	2012	2011	2010
Production (Mcf)	32,580,756	32,964,647	33,378,855
Total Production Costs (including capital expenses)	$ 67,790,539	$ 70,849,834	$ 61,766,699
Average Production Costs per unit of Production	$ 2.0807	$ 2.1493	$ 1.8505
Lease Operating Expenses	$ 34,804,029	$ 34,249,734	$ 32,416,413
Average Lifting Cost per unit of Production	$ 1.0682	$ 1.0390	$ .9712

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 Underlying Properties totaled 32,580,756 Mcf during 2012.

Gas produced from the Underlying Properties is processed at one of the following five plants: Chaco, Val Verde, Milagro, Ignacio, and Kutz, all located in the San Juan Basin. All of such gas other than that processed at Kutz is being sold to Chevron USA, Inc. (Chevron) under a contract with Burlington dated April 1, 2011 which provides for the delivery of gas through March 31, 2013 and from year to year thereafter. Because neither party gave notice of termination, the term of the Chevron contract has automatically been extended through at least March 31, 2014.

Gas produced from the Underlying Properties and processed at Kutz is being sold under three separate contracts with Pacific Gas and Electric Company (PG&E), Shell Energy North America (US), LP (Shell) and New Mexico Gas Company, Inc. (NMGC). A fourth contract for the purchase of summer only supplies by Salt River Project Agricultural Improvement and Power District expired October 2012. Both PG&E and Shell have given notice of the termination of their respective contracts effective March 31, 2013, and Burlington has circulated requests for proposal soliciting bids for the purchase of those volumes commencing April 1, 2013. The NMGC contract for the sale of certain winter only supplies of the Kutz gas is for a five-year term expiring March 31, 2017.

All four of the current contracts provide for (i) the delivery of such gas at various delivery points through their respective termination dates and from year-to-year thereafter, until terminated by either party upon notice of between six and twelve months; and (ii) the sale of such gas at prices which fluctuate in accordance with the published indices for gas sold in the San Juan Basin of northwestern New Mexico.

Burlington contracts with Williams Four Corners, LLC (WFC) and Enterprise Field Services, LLC (EFS) for the gathering and processing of virtually all of the gas produced from the Underlying Properties. Four new contracts were entered into with WFC to be effective for terms of 15 years commencing April 1, 2010. Burlington has also signed a new agreement with EFS effective November 1, 2011 for a term of 15 years. Burlington has disclosed to the Trust a summary of that agreement which the Trust has reviewed with its consultants, subject to conditions of confidentiality.

Confidentiality agreements with gatherers and 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 and gas receipt points. 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 Annual Report on Form 10-K:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. See 17 CFR 210.4-10(a)(6).

Estimated future net revenues are computed by applying current oil and gas prices (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. See 17 CFR 210.4-10(c)(4)(A). Estimated future net revenues are sometimes referred to in this Annual Report on 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%. See 17 CFR 210.4-10(c)(4)(A).

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. See 17 CFR 210.4-10(a)(22).

Proved reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions. See 17 CFR 210.4-10(a)(22); 17 CFR 210.4-10(a)(2)(iii).

Proved undeveloped reserves or PUDs are undeveloped oil and gas reserves.

Reasonable certainty means (i) if deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered or (ii) if probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease. See 17 CFR 210.4-10(a)(24).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project. See 17 CFR 210.4-10(a)(26).

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. See 17 CFR 210.4-10(a)(31).

The process of estimating oil and gas reserves is complex and requires significant judgment. The Trust, however, does not have information that would be available to a company with oil and gas operations because detailed information is not generally available to owners of royalty interests. Given this, the Trustee accumulates information and data provided by Burlington regarding the Royalty derived from the Underlying Properties and provides such information to Cawley, Gillespie & Associates, Inc. (CG&A). CG&A extrapolates from such information estimates of the reserves attributable to the Underlying Properties based on its expertise in the oil and gas fields where the Underlying Properties are situated, as well as publicly available information. The Trust maintains internal controls and procedures applicable to reserve estimation which are reviewed annually and updated as required and reviews the reserve reports prepared by CG&A for reasonableness. The Trust s internal controls and procedures regarding reserve estimates require proved reserves to be determined and disclosed in compliance with the SEC definitions and guidance.

The Trust does not maintain an internal petroleum engineering department and instead relies upon CG&A for a qualified, independent report of estimated reserves. The Trust verifies the qualifications and credentials of CG&A to prepare reserve estimates on behalf of the Trust. The independent petroleum engineers reports as to the proved oil and gas reserves as of December 31, 2009, 2010, 2011 and 2012 were prepared by CG&A. CG&A, whose firm registration number is F-693, was founded in 1961 and is nationally recognized in the evaluation of oil and gas properties. The technical person at CG&A primarily responsible for overseeing the reserve estimate with respect to the Trust is Zane Meekins. Mr. Meekins has been a practicing petroleum engineering consultant since 1989, with over 24 years of practice experience in petroleum engineering. He is a registered professional engineer in the State of Texas (License No. 71055). He graduated from Texas A&M University in 1987, *summa cum laude*, with a B.S. in Petroleum Engineering. CG&A and Mr. Meekins have indicated that they meet or exceed all requirements set forth in Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The following table presents a reconciliation of proved reserve quantities attributable to the Royalty from December 31, 2009, to December 31, 2012, (in thousands):

	Crude Oil (Bbls)	**Natural Gas (Mcf)**
Reserves as of December 31, 2009	207	133,836
Revisions of previous estimates	87	21,223
Extensions, discoveries and other additions	6	4,150
Production	(32)	(17,103)
Reserves as of December 31, 2010	268	142,106
Revisions of previous estimates	6	6,873
Extensions, discoveries and other additions	8	2,228
Production	(27)	(15,266)
Reserves as of December 31, 2011	255	135,941
Revisions of previous estimates	(45)	(24,802)
Extensions, discoveries and other additions	10	3,569
Production	(16)	(10,260)
Reserves as of December 31, 2012	204	104,448

Estimated quantities of proved developed oil and gas reserves as of December 31, 2012, 2011, and 2010 were as follows (in thousands):

	2012	**2011**	**2010**
Crude Oil (Bbls)	192	239	253

Natural Gas (Mcf)	101,132	130,707	135,170

A summary of estimated quantities by geographic area for total proved and proved undeveloped oil and gas reserves as of December 31, 2012 were as follows (in thousands):

Reserves Category	**Crude Oil Reserves (Bbls)**	**Natural Gas Reserves (Mcf)**
Developed:		
United States	192	101,132
Other Countries	0	0
Undeveloped:		
United States	12	3,316
Other Countries	0	0
Total Proved	204	104,448

Based on information provided by Burlington, there were 55 PUDs identified as of December 31, 2012, as compared to 75 as of December 31, 2011. This estimate does not include 3 PUDs identified but not drilled within five years from date of booking. For the year ended December 31, 2012, an aggregate of 3 Mbbls of oil and 1,913 MMcf of gas were converted from proved undeveloped reserves to proved developed reserves.

The current estimate has also been adjusted to take into account the elimination of PUDs no longer deemed commercially viable due to declines in the market price of natural gas, as well as new PUDs identified during the year and those converted to proved developed, all in the ordinary course of business. See Item 2. Properties, above, for a discussion of historical and budgeted investment and progress to convert PUDs to proved developed.

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 annual average prices of oil and gas relating to the enterprise s proved reserves to the year-end quantities of those reserves, less estimated future expenditures (based on current costs) of developing and producing the proved reserves, and assuming continuation of existing economic conditions. Future price changes are only considered to the extent provided by contractual arrangements in existence at year-end. The standardized measure of discounted future net cash flows is achieved by using a discount rate of 10% a year to reflect the timing of future 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 2012, 2011, and 2010 changes in the standardized measure of discounted future net cash flows related to future royalty income from proved reserves are as follows (in thousands):

	2012	2011	2010
Balance, January 1	$ 384,406	$ 382,008	$ 278,033
Revisions of prior-year estimates, change in prices and other	(178,205)	27,753	146,577
Extensions, discoveries and other additions	3,409	4,474	9,567
Accretion of discount	38,441	38,201	27,803
Royalty Income	(34,486)	(68,030)	(79,972)
Balance, December 31	$ 213,565	$ 384,406	$ 382,008

Reserve quantities and revenues shown in the tables above for the Royalty were estimated from projections of reserves and revenues attributable to the combined Burlington 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, if any, available to production from coal seam wells.

For 2012, $3.30 per Mcf of gas and $82.87 per Bbl of oil were used in determining future net revenue. These prices were based on a 12-month unweighted average of the first-day-of the month pricing of $2.64 per MMBtu of NYMEX natural gas and $94.71 per Bbl of West Texas Intermediate oil. The downward revision in reserve quantities for 2012 is due to the natural decline in the production from the properties as well as lower average gas prices during 2012 as compared to 2011.

For 2011, $4.82 per Mcf of gas and $84.36 per Bbl of oil were used in determining future net revenue. These prices were based on a 12-month unweighted average of the first-day-of the month pricing of $4.12 per MMBtu of NYMEX natural gas and $96.19 per Bbl of West Texas Intermediate oil. The slightly downward revision in reserve quantities for 2011 is primarily due to the natural decline in the production from the properties.

For 2010, $4.63 per Mcf of gas and $68.38 per Bbl of oil were used in determining future net revenue. These prices were based on a 12-month unweighted average of the first-day-of-the-month pricing of $4.38 per MMBtu of NYMEX natural gas and $79.43 per Bbl of West Texas Intermediate oil. The upward revision in reserve quantities for 2010 was due primarily to higher average gas prices during 2010 as compared to 2009.

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, 2012, 2011, and 2010 (in thousands, except amounts per Unit):

	2012		2011		2010	
	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	$ 364,027	$ 213,565	$ 670,246	$ 384,406	$ 655,347	$ 382,008
Proved Developed	$ 353,091	$ 212,551	$ 644,044	$ 373,492	$ 626,106	$ 367,835
Total Proved Per Unit	$ 7.81	$ 4.58	$ 14.38	$ 8.25	$ 14.06	$ 8.20

Estimated quantities of proved reserves declined in 2012 as compared to 2011 primarily due to significantly lower gas prices in 2012. 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 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 require the analysis of additional parameters. Reserve estimates were not filed with any Federal authority or agency other than the SEC.

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 Burlington can produce and to limit the number of wells or the locations at which Burlington 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 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.

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 to natural gas sales 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 depends on pipelines that transport such gas in interstate commerce and whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act.

Section 45 Tax Credit

Sales of gas production from certain coal seam wells drilled prior to January 1, 1993, qualified for federal income tax credits under Section 29 (now Section 45K) of the Internal Revenue Code of 1986 (as amended, the Code) through 2002 but not thereafter. Accordingly, under present law, the Trust s production and sale of gas from coal seam wells does not qualify for tax credit under Section 45K of the Code (the Section 45 Tax Credit). Congress has at various times since 2002 considered energy legislation, including provisions to reinstate the Section 45 Tax Credit in various ways and to various extents, but no legislation that would qualify the Trust s current production for such credit has been enacted. For example, in December 2010, new energy tax legislation was enacted which, among other things, modified the Section 45 Tax Credit in several respects, but did not extend the credit for production from coal seam wells. No prediction can be made as to what future tax legislation affecting Section 45K of the Code may be proposed or enacted or, if enacted, its impact, if any, on the Trust and the Unit Holders.

Passive Loss Rules

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 such as that derived through the Trust will generally be treated as portfolio income that may not be offset or reduced by passive losses.

Climate Change Regulation

The oil and natural gas industry is also subject to compliance with federal, state and local regulations and laws regarding the effects of climate change. These laws and regulations have impacted, and will in the future continue to impact, the production, gathering, marketing and transportation of oil and natural gas.

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***

As discussed herein under Part II, Item 9A (Controls and Procedures), due to the pass-through nature of the Trust, Burlington is the primary source of the information disclosed in this Annual Report on Form 10-K and the other periodic reports filed by the Trust with the SEC. Although the Trustee receives periodic updates from Burlington regarding activities which may relate to the Trust, the Trust s ability to timely report certain information required to be disclosed in the Trust s periodic reports is dependent on Burlington s timely delivery of the information to the Trust.

On March 14, 2008, Burlington notified the Trust that the distribution for March would be reduced by $4,921,578. Burlington described this amount as the Trust s portion of what Burlington had paid to settle claims for the underpayment of royalties in the case styled United States of America ex rel. Harrold E. (Gene) Wright v. AGIP Petroleum Co. et al., Civil Action No. 5:03CV264 (formerly 9:98-CV-30) (E.D. Tex.). The Trust s consultants continue to analyze this settlement as it may apply to the Trust.

Following mediation conducted on April 8 and 23, 2010, Burlington and the Trust entered into a settlement of previously reported litigation styled San Juan Basin Royalty Trust vs. Burlington Resources Oil & Gas Company, L.P., No. D1329-CV-08-751, in the District Court of Sandoval County, New Mexico, 13th Judicial District. The dispute subject to the mediation arose out of an arbitrator s award in 2005 in favor of the Trust. That award effectively resolved five compliance audit issues, but Burlington argued in subsequent litigation that one of those issues was beyond the scope of the matters agreed to be submitted to arbitration. Pursuant to the settlement, the litigation was dismissed, Burlington paid $2,600,000 to the Trust in May 2010, and released its claims for attorneys fees.

Burlington has informed the Trust that pursuant to an Order to Perform issued by the Minerals Management Service (MMS) dated June 10, 1998 (the MMS Order), the Jicarilla Apache Nation (the Jicarilla) alleged that in valuing production for royalty purposes one must perform (i) a major portion analysis, which calculates 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, which computes royalties on the greater of (a) the value of gas prior to processing or (b) the combined value of processed residue gas and plant products plus the value of any condensate recovered downstream without processing. The MMS Order alleged that Burlington s dual accounting calculations on Native American leases were based on less than major portion prices. In 2000, Burlington and the Jicarilla entered into a settlement agreement resolving the issues associated with the dual accounting calculation. The major portion calculation issue remains outstanding. Burlington takes the position that a judgment or settlement could entitle Burlington to reimbursement from the Trust for past periods.

In 2007 Burlington obtained an Administrative Order from the Department of the Interior (the DOI) rejecting that portion of the MMS Order requiring Burlington to calculate and pay additional royalties based on the major portion price derived by the MMS. The Jicarilla filed suit solely against the DOI in the United States District Court for the District of Columbia in an action entitled 1:07-CV-00803-RJL, Jicarilla Apache Nation v. Department of Interior (the DOI Case) seeking a declaration that the Administrative Order is unlawful and of no force and effect, as well as an injunction requiring enforcement of the underlying major portion orders that were rejected by the Assistant Secretary. In 2009, a summary judgment was entered by the district court in the DOI Case upholding the Administrative Order and dismissing the Jicarilla s claims. The Jicarilla appealed to the U.S. Court of Appeals for the D.C. Circuit. On July 16, 2010, the U.S. Court of Appeals held that the 2007 Administrative Order dismissing the Jicarilla claims was arbitrary and capricious with respect to January 1984 through February 1988 production periods and by Memorandum Order dated October 7, 2011, remanded the matter to the DOI for further proceedings. While a judgment or settlement in the DOI Case could impact the Royalty Income of the Trust, Burlington has informed the Trust that it does not have sufficient information to estimate a range of loss for the Trust because the DOI has not provided a major portion calculation for the January 1984 to February 1988 time period as required by the July 16, 2010 Court of Appeals ruling described above. Burlington indicates that the situation will not be alleviated until the DOI provides Burlington with a new Order to Perform or similar notice, but that it cannot predict when or if the DOI will provide such information or notice. The Trust s consultants will continue to monitor development in this matter and analyze the appropriateness of the allocation, if any, by Burlington of any portion of any settlement or judgment in calculating the Royalty.

In May 2011, a verdict was entered in the case styled Abraham et al. v. BP America Production Company, Case No. 6:09-cv-00961, in the U.S. District Court for the District of New Mexico, awarding the plaintiffs approximately $9.74 million in damages and $3.5 million in pre-judgment interest and costs based upon a jury finding that the defendant had failed to pay royalties consistent with market value for gas produced in the San Juan Basin. But on appeal, the Tenth Circuit reversed the judgment of the District Court and remanded the case for a new trial. Notice has been received that a settlement agreement has been reached among the parties dated December 19, 2012 pursuant to which BP will pay $10 million, plus interest, to the plaintiffs. To be effective, the proposed settlement requires the approval of the District Court. A hearing on the settlement is scheduled for March 19, 2013. The Trust is a member of the plaintiff class. If there is ultimately a distribution to the plaintiff class, it is uncertain whether any amount distributed to the Trust will be material. The Trustee will continue to monitor these proceedings.

ITEM 4. ***Not Applicable.***

PART II

ITEM 5. ***MARKET FOR REGISTRANT S UNITS, RELATED UNIT HOLDER MATTERS AND ISSUER PURCHASES OF UNITS***

The information under Units of Beneficial Interest in the Trust s Annual Report to Unit Holders for the year ended December 31, 2012, is incorporated herein 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***

	2012	2011	2010	2009	2008
Royalty Income	$ 34,485,777	$ 68,029,748	$ 79,971,751	$ 31,888,681	$ 144,588,156
Distributable income	33,481,687	67,190,000	78,355,835	30,173,056	143,081,245
Distributable income per Unit	0.718358	1.441573	1.681139	.647367	3.069833
Distributions per Unit	0.718358	1.441573	1.681139	.647367	3.069833
Total assets, December 31	13,583,556	20,246,377	19,969,007	22,185,213	25,377,265

ITEM 7. ***TRUSTEE S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION***

The Description of the Properties in the Trust s Annual Report to Unit Holders for the year ended December 31, 2012, is herein incorporated by reference.

Gas and Oil Production

Total gas and oil production from the Underlying Properties for the five years ended December 31, 2012 were as follows:

	2012	2011	2010	2009	2008
Gas Mcf	32,580,756	32,964,647	33,378,855	35,067,662	34,527,043
Mcf per Day	89,018	90,314	91,449	96,076	94,336
Oil-Bbls	50,617	58,908	62,675	58,603	50,323
Bbls per Day	138	161	172	161	137

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

	2012	2011	2010	2009	2008
Gas Mcf	10,259,791	15,265,827	17,102,939	9,823,255	19,529,046
Average Price (per Mcf)	$ 3.56	$ 4.76	$ 4.86	$ 3.48	$ 8.28
Oil Bbls	16,369	26,981	31,808	15,961	28,221
Average Price (per Bbl)	$ 84.36	$ 81.08	$ 67.08	$ 53.45	$ 99.32

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.

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, market conditions, and increased capital spending to generate production from new and existing wells, as offset by the natural production decline curve. Also, 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.

Gas produced from the Underlying Properties is processed at one of the following five plants: Chaco, Val Verde, Milagro, Ignacio, and Kutz, all located in the San Juan Basin. All of such gas other than that processed at Kutz is being sold to Chevron USA, Inc. (Chevron) under a contract with Burlington dated April 1, 2011 which provides for the delivery of gas through March 31, 2013 and from year to year thereafter. Because neither party gave notice of termination, the term of the Chevron contract has automatically been extended through at least March 31, 2014.

Gas produced from the Underlying Properties and processed at Kutz is being sold under three separate contracts with Pacific Gas and Electric Company (PG&E), Shell Energy North America (US), LP (Shell) and New Mexico Gas Company, Inc. (NMGC). A fourth contract for the purchase of summer only supplies by Salt River Project Agricultural Improvement and Power District expired October 2012. Both PG&E and Shell have given notice of the termination of their respective contracts effective March 31, 2013, and Burlington has circulated requests for proposal soliciting bids for the purchase of those volumes commencing April 1, 2013. The NMGC contract for the sale of certain winter only supplies of the Kutz gas is for a five-year term expiring March 31, 2017.

All four of the current contracts provide for (i) the delivery of such gas at various delivery points through their respective termination dates and from year-to-year thereafter, until terminated by either party upon notice of between six and twelve months; and (ii) the sale of such gas at prices which fluctuate in accordance with the published indices for gas sold in the San Juan Basin of northwestern New Mexico.

Burlington contracts with Williams Four Corners, LLC (WFC) and Enterprise Field Services, LLC (EFS) for the gathering and processing of virtually all of the gas produced from the Underlying Properties. Four new contracts were entered into with WFC to be effective for terms of 15 years commencing April 1, 2010. Burlington has also signed a new agreement with EFS effective November 1, 2011 for a term of 15 years. Burlington has disclosed to the Trust a summary of that agreement which the Trust has reviewed with its consultants, subject to conditions of confidentiality.

Confidentiality agreements with gatherers and 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 and gas receipt points. Such disclosure could compromise the ability to compete effectively in the marketplace for the sale of gas produced from the Underlying Properties.

Royalty Income

Royalty Income consists of monthly Net Proceeds attributable to the Royalty. Royalty Income for the five years ended December 31, 2012 was determined as shown in the following table:

	2012	2011	2010	2009	2008
Gross Proceeds From The Underlying Properties:					
Gas	$ 109,817,282	$ 156,770,429	$ 164,194,440[(2)]	$ 117,091,623	$ 274,759,523
Oil	4,200,625	4,785,736	4,201,260	2,917,081	4,944,422
Other	(246,332)[(1)]	-0-	-0-	-0-	-0-
Total	$ 113,771,575	$ 161,556,165	$ 168,395,700	$ 120,008,704	$ 279,703,945
Capital Expenditures	$ 22,195,936	$ 21,052,419	$ 13,101,962	$ 33,596,883	$ 26,992,650
Severance tax Gas	10,088,154	14,343,854	14,816,771	10,526,019	25,500,279
Severance Tax Oil	417,036	482,396	407,627	283,744	483,725
Other	-0-	-0-	-0-	1,020	-0-
Lease Operating Expenses and Property Taxes	35,089,413	34,971,165	33,440,339	33,082,796	33,943,082
Total	$ 67,790,539	$ 70,849,834	$ 61,766,699	$ 77,490,462	$ 86,919,736
Net Profits	$ 45,981,036	$ 90,706,331	$ 106,629,001	$ 42,518,242	$ 192,784,209
Net Overriding Royalty Interest	75%	75%	75%	75%	75%
Royalty Income	$ 34,485,777	$ 68,029,748	$ 79,971,751	$ 31,888,681	$ 144,588,156

(1) *Funds recovered by Burlington due to an overpayment of compliance audit exceptions.*

(2) *In May 2010, gas proceeds included $2,600,000 received in settlement of litigation.*

Distributable Income

Distributable Income (as that term is used herein) 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, 2012, Distributable Income was $33,481,687 as compared to $67,190,000 for the year ended December 31, 2011. Distributable Income in 2010 was $78,355,835.

The Trust received Royalty Income of $34,485,777 and interest income of $570,291 in 2012. After deducting administrative expenses of $1,574,381, Distributable Income for 2012 was $33,481,687 ($0.718358 per Unit). In 2011, Royalty Income was $68,029,748, interest income was $679,952, and administrative expenses were $1,519,700, resulting in Distributable Income of $67,190,000 ($1.441573 per Unit). The decrease in Distributable Income from 2011 to 2012 was primarily attributable to lower natural gas pricing. Interest earnings in 2012 were lower as compared to 2011, primarily due to additional interest received in 2011 on late payments of Gross Proceeds used in the calculation of the Royalty. Administrative expenses were higher in 2012, as compared to 2011 primarily as a result of differences in timing in the receipt and payment of these expenses.

In 2010, the Trust received Royalty Income of $79,971,751 and interest income of $309,437. After deducting administrative expenses of $1,925,353, Distributable Income for 2010 was $78,355,835 ($1.681139 per Unit). The decrease in Distributable Income from 2010 to 2011 was primarily attributable to lower natural gas pricing, but also as a result of material increases in capital expenditures. Interest earnings in 2011 were higher as compared to 2010, primarily due to an increase in the amount of interest received on late payments of

Gross Proceeds used in the calculation of the Royalty. Administrative expenses were lower in 2011, as compared to 2010 primarily as a result of differences in timing in the receipt and payment of these expenses and also as a result of decreased costs associated with the settlement of litigation described in Part I, Item 3.

The Trustee has been informed that the New Mexico Oil and Gas Proceeds and Pass-Through Entity Withholding Tax Act (the Withholding Tax Act) requires remitters who pay certain oil and gas proceeds from production on New Mexico wells, to withhold income taxes from such proceeds in the case of certain nonresident recipients. The Trustee, on advice of New Mexico counsel, has observed that net profits interests, such as the Royalty, and other types of interests, the extent of which cannot be determined with respect to a specific share of the oil and gas production, as well as amounts deducted from payments that are for expenses related to oil and gas production, are excluded from the withholding requirements of the Withholding Tax Act. Unit Holders are reminded to consult with their tax advisors regarding the applicability of New Mexico income tax to distributions received from the Trust by a Unit holder.

Operating Expenses

Monthly operating expenses of the Underlying Properties, exclusive of property taxes, in 2012 averaged approximately $2,900,336, as compared to the $2,854,144 average in 2011. Operating expenses averaged higher in 2012 primarily because of compliance with increased regulation requirements. The average for 2010 was $2,701,368.

Settlements

As part of the September 4, 1996, settlement of the litigation filed by the Trustee on June 4, 1992 against Burlington and Southland, the Trustee and Burlington established a formal protocol pursuant to which compliance auditors retained by the Trustee gained improved access to Burlington s books and records as applicable to the Underlying Properties. The audit process was initiated in 1996 and, since inception, has resulted in audit exceptions being granted by and payments or credits received from Burlington totaling approximately $41.8 million.

Following mediation conducted on April 8 and 23, 2010, Burlington and the Trust entered into a settlement of previously reported litigation styled San Juan Basin Royalty Trust vs. Burlington Resources Oil & Gas Company, L.P. No. D1329-CV08-751, in the District Court of Sandoval County, New Mexico, 13th Judicial District. The dispute subject to the mediation arose out of an arbitrator s award in 2005 in favor of the Trust. That award effectively resolved five compliance audit issues, but Burlington argued in subsequent litigation that one of those issues was beyond the scope of the matters agreed to be submitted to arbitration. Pursuant to the settlement, the litigation was dismissed, Burlington paid $2,600,000 to the Trust in May 2010, and released its claims for attorneys fees.

Capital Expenditures

Capital expenses of $22.2 million were included in calculating Royalty Income paid to the Trust in calendar year 2012, and included expenditures for the drilling and completion of 28 gross (7.97 net) conventional wells. There were six gross (4.39 net) conventional wells in progress as of December 31, 2012. The Yert 1-H is an exploratory well. Burlington indicates it expects to have production data on the Yert 1-H by the end of the first quarter of 2013. All of the other wells were development wells. There were no dry exploratory or development wells drilled in 2012.

Approximately $14.1 million of capital expenditures covered 114 projects budgeted for 2012. Approximately $13.2 million of those costs were incurred in drilling 24 new wells commenced in 2012 to be operated by Burlington and none to be operated by third parties. The balance of the expenditures allocable to 2012 projects was attributable to the workover of existing wells and the maintenance and improvement of production facilities.

The $22.2 million of capital expenses reported by Burlington for 2012 included approximately $8.1 million attributable to the capital budgets for prior years. This occurs because capital expenditures are deducted in calculating royalty income in the month they accrue, and projects within a given year s budget often extend into subsequent years. Further, Burlington 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. In addition, with respect to wells not operated by Burlington, Burlington 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.

Results of the 4th Quarters of 2012 and 2011

For the three months ended December 31, 2012, Distributable Income was $3,860,972 ($0.082838 per Unit), which was less than the $18,936,560 ($0.406288 per Unit) of income distributed during the same period in 2011. The decrease in Distributable Income resulted primarily from a decrease in the average gas price, but also due to increased capital costs and lease operating expenses in the fourth quarter of 2012. In addition, there was a miscalculation by Burlington for the months of April through July 2012 which caused lease operating expenses and capital expenditures to be understated by approximately 25% (the 2012 Calculation Error). The 2012 Calculation Error caused capital costs to be understated by $333,644 in July 2012 and to be overstated by a total of $985,356 in August and September 2012 as that error was corrected.

As a result of the 2012 Calculation Error, the Royalty income due the Trust for the four months of April through July 2012 was overpaid by approximately $3,386,861. As permitted under the terms of the Royalty conveyance document, Burlington offset the overpayment against Royalty income payable to the Trust over four consecutive months beginning with August 2012. Royalty income distributions to the Trust were reduced by $742,779 in August, $1,090,583 in September, $767,122 in October and $786,377 in November 2012.

Royalty Income of the Trust for the fourth quarter is based on actual gas and oil production during August through October of each year. Gas and oil sales for the quarters ended December 31, 2012 and 2011 were as follows:

	2012	2011
Underlying Properties		
Gas Mcf	7,734,664	8,575,777
Mcf per Day	84,072	93,215
Average Price (per Mcf)	$ 3.40	$ 4.87
Oil Bbls	12,287	15,590
Bbls per Day	134	169
Average Price (per Bbl)	$ 81.26	$ 76.03
Attributable to the Royalty		
Gas Mcf	1,179,548	4,218,794
Oil Bbls	1,965	7,594

The average price of gas decreased in the fourth quarter of 2012 compared to the same period of 2011. The price per barrel of oil during the fourth quarter of 2012 was $5.23 higher than that received in the fourth quarter of 2011. Gas production decreased in the fourth quarter of 2012 because new production brought on line in 2012 failed to completely offset the natural decline in production from existing wells.

Capital costs for the fourth quarter of 2012 totaled $8,308,921 compared to $5,254,281 during the same period of 2011. Lease operating expenses and property taxes for the fourth quarter of 2012 averaged $3,586,389 per month compared to $2,750,282 per month in the fourth quarter of 2011. Operating expenses were higher in the fourth quarter of 2012 than for the fourth quarter of 2011 because of compliance with increased regulation requirements, but also due to the timing of the receipt and payment of invoices. Based on 46,608,796 Units outstanding, the per-Unit distributions during the fourth quarters of 2012 and 2011 were as follows:

	2012	2011
October	$ .054593	$ .122104
November	.001119	.135166
December	.027126	.149018
Quarter Total	$ 0.082838	$ 0.406288

ITEM 7A. ***QUANTITATIVE AND QUALITATIVE DISCLOSURES 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 is prohibited from engaging in any business or commercial activity of any kind whatsoever, including borrowing transactions, other than the Trust s ability to borrow money periodically as necessary to pay expenses, liabilities and obligations of the Trust that cannot be paid out of cash held by the Trust. 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 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 gas, oil and/or natural gas liquids from the Underlying Properties. Burlington is responsible for such marketing.

ITEM 8. ***FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA***
Statements of Assets, Liabilities, and Trust Corpus

December 31, 2012 and 2011

	2012	2011
ASSETS		
Cash and Short-Term Investments	$ 1,420,096	$ 7,101,319
Net Overriding Royalty Interests in Producing Oil and Gas Properties Net	12,163,460	13,145,058
TOTAL	$ 13,583,556	$ 20,246,377
LIABILITIES & TRUST CORPUS		
Distribution Payable to Unit Holders	$ 1,264,307	$ 6,945,530
Cash Reserves	155,789	155,789
Trust Corpus 46,608,796 Units of Beneficial Interest Authorized and Outstanding	12,163,460	13,145,058
TOTAL	$ 13,583,556	$ 20,246,377

Statements of Distributable Income

For each of the years ended December 31

	2012	2011	2010
Royalty Income	$ 34,485,777	$ 68,029,748	$ 79,971,751
Interest Income	570,291	679,952	309,437
	35,056,068	68,709,700	80,281,188
Expenditures General and Administrative	1,574,381	1,519,700	1,925,353
Distributable Income	$ 33,481,687	$ 67,190,000	$ 78,355,835
Distributable Income per Unit (46,608,796 Units)	$ 0.718358	$ 1.441573	$ 1.681139

Statements of Changes In Trust Corpus

For each of the years ended December 31

	2012	2011	2010
Trust Corpus, Beginning of Period	$ 13,145,058	$ 14,745,884	$ 16,843,731
Amortization of Net Overriding Royalty Interest	(981,598)	(1,600,826)	(2,097,847)
Distributable Income	33,481,687	67,190,000	78,355,835
Distributions Declared	(33,481,687)	(67,190,000)	(78,355,835)
Trust Corpus, End of Period	$ 12,163,460	$ 13,145,058	$ 14,745,884

These Financial Statements should be read in conjunction with the accompanying Notes to Financial Statements included herein.

Notes to Financial Statements

1. Trust Organization and Provisions

The San Juan Basin Royalty Trust (the Trust) was established as of November 1, 1980. Southland Royalty Company (Southland) conveyed to the Trust a 75% net overriding royalty interest (the Royalty) which burdens certain of Southland s oil and gas leasehold interests (the Underlying Properties) in properties located in the San Juan Basin in northwestern New Mexico. Through an acquisition completed March 24, 2006, Compass Bank succeeded TexasBank as Trustee (herein so called) of the Trust. On September 7, 2007, Compass Bancshares, Inc. was acquired by Banco Bilbao Vizcaya Argentaria, S.A. (BBVA) and is now a wholly-owned subsidiary of BBVA.

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. Holders of Units are referred to herein as Unit Holders.

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 sell up to one percent (1%) of the value (based on prior year engineering reports) of the Royalty in any 12 month period, but otherwise may not sell all or any part of the Royalty unless approved by holders of 75% of all Units outstanding. In either 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 by the Trustee. 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 10 business days after the monthly record date, which is generally the last business day of each calendar month.

The cash received by the Trustee consists of the proceeds received by the owner of the Underlying Properties 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, 2012 and 2011 aggregated $121,112,068 and $120,130,470, respectively.

Notes to Financial Statements (Continued)

3. Basis of Accounting

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

The net proceeds attributable to the Royalty (the Royalty Income) recorded for a month is the amount computed and paid by the owner of the Underlying Properties, Burlington Resources Oil & Gas Company LP (Burlington), the present owner of the Underlying Properties, to the Trustee for the Trust. Royalty Income consists of the proceeds received by Burlington 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%. The calculation of net proceeds by Burlington for any month includes adjustments to proceeds and costs for prior months and impacts the Royalty Income paid to the Trust and the distribution to Unit Holders for that month.

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 applicable to the Underlying Properties over gross proceeds from such properties must be recovered from future net proceeds before Royalty Income is again paid to the Trust.

The financial statements of the Trust differ from financial statements prepared in accordance with United States 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; expenses are recorded when paid instead of when incurred; and amortization of the Royalty calculated on a unit-of-production basis is charged directly to trust corpus instead of as an expense. The basis of accounting used by the Trust is widely used by royalty trusts for financial reporting purposes.

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 Trust is a widely held fixed investment trust (WHFIT) classified as a non-mortgage widely held fixed investment trust (NMWHFIT) for federal income tax purposes. The Trustee is the representative of the Trust that will provide tax information in accordance with the applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT and a NMWHFIT.

The Royalty constitutes an economic interest in oil and gas properties for federal income tax purposes. Unit Holders must report their share of the production 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 such tax treatment.

Sales of gas production from certain coal seam wells drilled prior to January 1, 1993, qualified for federal income tax credits under Section 29 (now Section 45K) of the Internal Revenue Code of 1986, as amended (the Code), through 2002 but not thereafter. Accordingly, under present law, the Trust s production and sale of gas from coal seam wells does not qualify for tax credit under Section 45K of the Code (the Section 45 Tax Credit). Congress has at various times since 2002 considered energy legislation, including provisions to reinstate the Section 45 Tax Credit in various ways and to various extents, but no legislation that would qualify

Notes to Financial Statements (Continued)

the Trust s current production for such credit has been enacted. For example, in December 2010, new energy tax legislation was enacted which, among other things, modified the Section 45 Tax Credit in several respects, but did not extend the credit for production from coal seam wells. No prediction can be made as to what future tax legislation affecting Section 45K of the Code may be proposed or enacted or, if enacted, its impact, if any, on the Trust and the Unit Holders.

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 such as that derived through the Trust will generally be treated as portfolio income that may not be offset or reduced by passive losses.

Tax positions taken by the Trust related to the Trust s pass-through status and state tax positions have been reviewed, and the Trustee is of the opinion that material positions taken would more likely than not be sustained by examination. In accordance with the Trust s basis of accounting discussed in Note 3, the Trust would only recognize the impact of tax positions that were not upheld at the time of payment. As of December 31, 2012, the Trust s tax years 2009 to 2011 remain subject to examination.

5. Certain Contracts

Gas produced from the Underlying Properties is processed at one of the following five plants: Chaco, Val Verde, Milagro, Ignacio, and Kutz, all located in the San Juan Basin. All of such gas other than that processed at Kutz is being sold to Chevron USA, Inc. (Chevron) under a contract with Burlington dated April 1, 2011 which provides for the delivery of gas through March 31, 2013 and from year to year thereafter. Because neither party gave notice of termination, the term of the Chevron contract has automatically been extended through at least March 31, 2014.

Gas produced from the Underlying Properties and processed at Kutz is being sold under three separate contracts with Pacific Gas and Electric Company (PG&E), Shell Energy North America (US), LP (Shell) and New Mexico Gas Company, Inc. (NMGC). A fourth contract for the purchase of summer only supplies by Salt River Project Agricultural Improvement and Power District expired October 2012. Both PG&E and Shell have given notice of the termination of their respective contracts effective March 31, 2013, and Burlington has circulated requests for proposal soliciting bids for the purchase of those volumes commencing April 1, 2013. The NMGC contract for the sale of certain winter only supplies of the Kutz gas is for a five-year term expiring March 31, 2017.

All four of the current contracts provide for (i) the delivery of such gas at various delivery points through their respective termination dates and from year-to-year thereafter, until terminated by either party upon notice of between six and twelve months; and (ii) the sale of such gas at prices which fluctuate in accordance with the published indices for gas sold in the San Juan Basin of northwestern New Mexico.

Burlington contracts with Williams Four Corners, LLC (WFC) and Enterprise Field Services, LLC (EFS) for the gathering and processing of virtually all of the gas produced from the Underlying Properties. Four new contracts were entered into with WFC to be effective for terms of 15 years commencing April 1, 2010. Burlington has also signed a new agreement with EFS effective November 1, 2011 for a term of 15 years. Burlington has disclosed to the Trust a summary of that agreement which the Trust has reviewed with its consultants, subject to conditions of confidentiality.

Confidentiality agreements with gatherers and 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 and gas receipt points. Such disclosure could compromise the ability to compete effectively in the marketplace for the sale of gas produced from the Underlying Properties.

Notes to Financial Statements (Continued)

6. Significant Customers

Information as to significant purchasers of oil and gas production attributable to the Trust s economic interests is included in Note 5 above.

7. Settlements and Litigation

In 2010, as part of the ongoing negotiations between the Trust and Burlington concerning a number of revenue and expense audit issues, an aggregate of $8,544,980 (of which $2,600,000 was paid in settlement of the Sandoval County litigation described below) was included in calculating net proceeds paid to the Trust, together with interest of $395,034 in settlement of certain of those audit issues.

In 2011, as part of the ongoing negotiations between the Trust and Burlington concerning a number of revenue and expense audit issues, an aggregate of $2,144,298 was included in calculating net proceeds paid to the Trust, together with interest of $673,189 in settlement of certain of those audit issues.

In 2012, as part of the ongoing negotiations between the Trust and Burlington concerning a number of revenue and expense audit issues, an aggregate of $1,521,302 was included in calculating net proceeds paid to the Trust, together with interest of $565,478 in settlement of certain of those audit issues.

In each instance, the settlements described above as having been paid to the Trust in 2010 through 2012 were received in the form of increased revenues, reduced overhead, interest on late payments, or other payments or allocations, many of which do not appear as separate line items in the tables included in the Trustee s Discussion and Analysis.

On March 14, 2008, Burlington notified the Trust that the distribution for March would be reduced by $4,921,578. Burlington described this amount as the Trust s portion of what Burlington had paid to settle claims for the underpayment of royalties in the case styled United States of America ex rel. Harrold E. (Gene) Wright v. AGIP Petroleum Co. et al., Civil Action No. 5:03CV264 (formerly 9:98-CV-30) (E.D. Tex.). The Trust s consultants continue to analyze this settlement as it may apply to the Trust.

Following mediation conducted on April 8 and 23, 2010, Burlington and the Trust entered into a settlement of previously reported litigation styled San Juan Basin Royalty Trust vs. Burlington Resources Oil & Gas Company, L.P., No. D1329-CV-08-751, in the District Court of Sandoval County, New Mexico, 13th Judicial District. The dispute subject to the mediation arose out of an arbitrator s award in 2005 in favor of the Trust. That award effectively resolved five compliance audit issues, but Burlington argued in subsequent litigation that one of those issues was beyond the scope of the matters agreed to be submitted to arbitration. Pursuant to the settlement, the litigation was dismissed, Burlington paid $2,600,000 to the Trust in May 2010, and released its claims for attorneys fees.

Burlington has informed the Trust that pursuant to an Order to Perform issued by the Minerals Management Service (MMS) dated June 10, 1998 (the MMS Order), the Jicarilla Apache Nation (the Jicarilla) alleged that in valuing production for royalty purposes one must perform (i) a major portion analysis, which calculates 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, which computes royalties on the greater of (a) the value of gas prior to processing or (b) the combined value of processed residue gas and plant products plus the value of any condensate recovered downstream without processing. The MMS Order alleged that Burlington s dual accounting calculations on Native American leases were based on less than major portion prices. In 2000, Burlington and the Jicarilla entered into a settlement agreement resolving the issues associated with the dual accounting calculation. The major portion calculation issue remains outstanding. Burlington takes the position that a judgment or settlement could entitle Burlington to reimbursement from the Trust for past periods.

Notes to Financial Statements (Continued)

In 2007 Burlington obtained an Administrative Order from the Department of the Interior (the DOI) rejecting that portion of the MMS Order requiring Burlington to calculate and pay additional royalties based on the major portion price derived by the MMS. The Jicarilla filed suit solely against the DOI in the United States District Court for the District of Columbia in an action entitled 1:07-CV-00803-RJL, Jicarilla Apache Nation v. Department of Interior (the DOI Case) seeking a declaration that the Administrative Order is unlawful and of no force and effect, as well as an injunction requiring enforcement of the underlying major portion orders that were rejected by the Assistant Secretary. In 2009, a summary judgment was entered by the district court in the DOI Case upholding the Administrative Order and dismissing the Jicarilla s claims. The Jicarilla appealed to the U.S. Court of Appeals for the D.C. Circuit. On July 16, 2010, the U.S. Court of Appeals held that the 2007 Administrative Order dismissing the Jicarilla claims was arbitrary and capricious with respect to January 1984 through February 1988 production periods and by Memorandum Order dated October 7, 2011, remanded the matter to the DOI for further proceedings. While a judgment or settlement in the DOI Case could impact the Royalty Income of the Trust, Burlington has informed the Trust that it does not have sufficient information to estimate a range of loss for the Trust because the DOI has not provided a major portion calculation for the January 1984 to February 1988 time period as required by the July 16, 2010 Court of Appeals ruling described above. Burlington indicates that the situation will not be alleviated until the DOI provides Burlington with a new Order to Perform or similar notice, but that it cannot predict when or if the DOI will provide such information or notice. The Trust s consultants will continue to monitor development in this matter and analyze the appropriateness of the allocation, if any, by Burlington of any portion of any settlement or judgment in calculating the Royalty.

In May 2011, a verdict was entered in the case styled Abraham et al. v. BP America Production Company, Case No. 6:09-cv-00961, in the U.S. District Court for the District of New Mexico, awarding the plaintiffs approximately $9.74 million in damages and $3.5 million in pre-judgment interest and costs based upon a jury finding that the defendant had failed to pay royalties consistent with market value for gas produced in the San Juan Basin. But on appeal, the Tenth Circuit reversed the judgment of the District Court and remanded the case for a new trial. Notice has been received that a settlement agreement has been reached among the parties dated December 19, 2012 pursuant to which BP will pay $10 million, plus interest, to the plaintiffs. To be effective, the proposed settlement requires the approval of the District Court. A hearing on the settlement is scheduled for March 19, 2013. The Trust is a member of the plaintiff class. If there is ultimately a distribution to the plaintiff class, it is uncertain whether any amount distributed to the Trust will be material. The Trustee will continue to monitor these proceedings.

8. 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.

9. 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, 2012 (in thousands, except per unit amounts):

2012	Royalty Income	Distributable Income	Distributable Income and Distribution Per Unit
First Quarter	$ 14,850	$ 14,625	$ .313776
Second Quarter	10,583	10,379	.222678
Third Quarter	4,926	4,617	.099066
Fourth Quarter	4,127	3,861	.082838
Total	$ 34,486	$ 33,482	$ 0.718358

Notes to Financial Statements (Continued)

2011	Royalty Income	Distributable Income	Distributable Income and Distribution Per Unit
First Quarter	$ 15,389	$ 14,869	$ .319015
Second Quarter	15,568	15,724	.337370
Third Quarter	17,940	17,660	.378900
Fourth Quarter	19,133	18,937	.406288
Total	$ 68,030	$ 67,190	$ 1.441573

Report of Independent Registered Public Accounting Firm

Compass Bank, Trustee

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, 2012 and 2011, and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by 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 accounting principles generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and trust corpus of the San Juan Basin Royalty Trust as of December 31, 2012 and 2011, and the distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2012, on the basis of accounting described in Note 3 to the financial statements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust s internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2013 expressed an unqualified opinion thereon.

/s/ Weaver and Tidwell, L.L.P.
Weaver and Tidwell, L.L.P.

Fort Worth, Texas

March 1, 2013

ITEM 9. ***CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE***

Within the two most recent fiscal years, there have been no changes in and disagreements with the Trust s independent accountants.

ITEM 9A. ***CONTROLS AND PROCEDURES***

The Trust maintains a system of disclosure controls and procedures that is designed to ensure 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 SEC s rules and forms. Due to the pass-through nature of the Trust, Burlington is the primary source of the information disclosed in this Form 10-K and the other periodic reports filed by the Trust with the SEC. Consequently, the Trust s ability to timely disclose relevant information in its periodic reports is dependent upon Burlington s delivery of such information. Accordingly, the Trust maintains disclosure controls and procedures designed to ensure that Burlington accurately and timely accumulates and delivers such relevant information to the Trustee and those who participate in the preparation of the Trust s periodic reports to allow for the preparation of such periodic reports and any decisions regarding disclosure.

The Conveyance transferring the Royalty to the Trust obligates Burlington to provide the Trust with certain information, including information concerning calculations of net proceeds owed to the Trust. Pursuant to the settlement of litigation in 1996 between the Trust and Burlington, Burlington agreed to newer, more formal financial reporting and audit procedures as compared to those provided in the Conveyance.

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, compliance auditors, marketing consultants, attorneys and petroleum engineers. These outside professionals advise the Trustee in its review and compilation of this information for inclusion in this Form 10-K and the other periodic reports provided by the Trust to the SEC.

The Trustee has evaluated the Trust s disclosure controls and procedures as of December 31, 2012 and has concluded that such disclosure controls and procedures are effective, at the reasonable assurance level (as such term is used in Rule 13a-15(f) of the Exchange Act), to ensure that material information related to the Trust is gathered on a timely basis to be included in the Trust s periodic reports. The Trustee has also concluded that its disclosure controls and procedures are effective to ensure that information required to be disclosed by the Trustee in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the timeframes specified in the Commission s rules and forms. In reaching its conclusions, the Trustee has considered the Trust s dependence on Burlington to deliver timely and accurate information to the Trust. Additionally, during the quarter ended December 31, 2012 there were no changes in the Trust s internal control over financial reporting (as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934) that materially affected, or are reasonably likely to materially affect, the Trust s internal control over financial reporting. The Trustee has reviewed neither the Trust s disclosure controls and procedures nor the Trust s internal control over financial reporting in concert with management, a board of directors or an independent audit committee. The Trust does not have, nor does the Indenture provide for, officers, a board of directors or an independent audit committee.

Trustee s Report on Internal Control Over Financial Reporting

Compass Bank, in its capacity as trustee (the Trustee) of San Juan Basin Royalty Trust (the Trust) is responsible for establishing and maintaining adequate internal control over financial reporting. The Trust s internal control over financial reporting is a process designed under the supervision of the Trustee to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Trust s financial statements for external purposes in accordance with a modified cash basis of accounting, which is a comprehensive basis of accounting other than U.S. generally accepted accounting principles.

As of December 31, 2012, the Trustee assessed the effectiveness of the Trust s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in Internal Control Integrated Framework , issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, the Trustee determined that the Trust maintained effective internal control over financial reporting as of December 31, 2012, based on those criteria.

Weaver and Tidwell, L.L.P., the independent registered public accounting firm that audited the financial statements of the Trust included in this Annual Report on Form 10-K, has issued an attestation report on the Trust s internal control over financial reporting as of December 31, 2012. The report, which expresses an unqualified opinion on the effectiveness of the Trust s internal control over financial reporting as of December 31, 2012, is included in this Item under the heading Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting .

Report of Independent Registered Public

Accounting Firm on Internal Control Over Financial Reporting

Compass Bank, Trustee

San Juan Basin Royalty Trust

We have audited San Juan Basin Royalty Trust s (the Trust) internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Compass Bank (the Trustee) is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the Trustee s Report On Internal Control Over Financial Reporting in Item 9A. Our responsibility is to express an opinion on the Trust s internal control over financial reporting based on our audit.

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the statements of assets, liabilities and trust corpus as of December 31, 2012 and 2011 and the related statements of distributable income and changes in trust corpus for each of the three years in the period ended December 31, 2012 of the Trust and our report dated March 1, 2013 expressed an unqualified opinion thereon.

/s/ Weaver and Tidwell, L.L.P.
Weaver and Tidwell, L.L.P.

Fort Worth, Texas

March 1, 2013

ITEM 9B. ***OTHER INFORMATION***

All information required to be disclosed by the Trust in a Current Report on Form 8-K during the fourth quarter of the year ended December 31, 2012, has previously been reported on a Form 8-K.

PART III

ITEM 10. ***DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT***

The Trust has no directors, executive officers or employees; the Trust is managed by a corporate trustee. Accordingly, the Trust does not have an audit committee, audit committee financial expert or a code of ethics applicable to executive officers. The Trustee, however, has adopted a policy regarding standards of conduct and conflicts of interest applicable to all directors, officers and employees of the Trustee. 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.

Section 16(a) Beneficial Ownership Reporting Compliance

The Trust has no directors or officers. Accordingly, only holders of more than 10% of the Trust s Units are required to file with the SEC initial reports of ownership of Units and reports of changes in such ownership. Based solely on a review of these reports, the Trust believes that the applicable reporting requirements of Section 16(a) of the Securities Exchange Act of 1934 were complied with for all transactions which occurred in 2012.

ITEM 11. ***EXECUTIVE COMPENSATION***

The Trust has no directors, executive officers or employees. Accordingly, the Trust does not have a compensation committee or maintain any equity compensation plans, and there are no Units reserved for issuance under any such plans. During the past three years the Trustee received total remuneration as follows:

Name of Individual or Entity	Year	Capacities in Which Served	Cash Compensation [1]
Compass Bank	2012	Trustee	$ 256,563
Compass Bank	2011	Trustee	$ 283,045
Compass Bank	2010	Trustee	$ 310,324

(1) Under the 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. As of January 1, 2003, the administrative fee due under items (i) and (ii) above will not 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***

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.

(a) Security Ownership of Certain Beneficial Owners. The following table sets forth as of February 22, 2013 information with respect to the only Unit Holder who was known to the Trustee to be a beneficial owner of more than 5 percent of the outstanding Units.

Name and Address of Beneficial Owner	Number of Units Beneficially Owned	Percent of Class
First Eagle Investment Management, LLC 1345 Avenue of the Americas New York, NY 10105(1)	4,569,990	9.80%
Seymour Schulich 20 Eglinton Avenue West, Suite 1900 Toronto ON, Canada M4R 1K8(2)	4,000,000	8.58%

(1) This information was provided to the SEC and to the Trustee in a Schedule 13G/A filed with the SEC on February 11, 2013, on behalf of First Eagle Investment Management, LLC.

(2) This information was provided to the SEC and to the Trustee in a Schedule 13G filed with the SEC on February 19, 2013, on behalf of Seymour Schulich.

(b) Security Ownership of Trustee. As of February 22, 2013, Compass Bank beneficially owned 21,012 Units, or less than one percent of the outstanding Units. Compass Bank has sole voting power over 5,000 of these Units and no voting power over the remaining 16,012. Compass Bank has neither the sole nor any shared power to dispose of any of such 21,012 Units.

ITEM 13. ***CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS***

The Trust has no directors or executive officers and is not empowered to carry on any business activity. Accordingly, there are no relationships or related transactions to which the Trust was a party that are required to be disclosed. See Item 11 for the remuneration received by the Trustee during the year ended December 31, 2012 and Item 12 for information concerning Units owned by the Trustee.

ITEM 14. ***PRINCIPAL ACCOUNTANT FEES AND SERVICES***

The following table presents fees for professional audit services rendered by Weaver and Tidwell, L.L.P., the Trust s principal accountants, for the audit of the Trust s annual financial statements for the fiscal years ended December 31, 2012 and 2011 and fees billed for other services rendered to the Trust by Weaver and Tidwell, L.L.P. during those periods.

	2012	2011
Audit Fees	$ 84,750	$ 81,355
Audit-Related Fees	-0-	-0-
Tax Fees	18,250	1,745
All Other Fees	-0-	-0-
Total	$ 103,000	$ 83,100

Audit Fees consist of fees billed for professional services rendered for the audit of the Trust s annual financial statements and internal control over financial reporting, review of the interim financial statements included in the Trust s quarterly reports and services that are normally provided by Weaver and Tidwell, L.L.P. in connection with statutory and regulatory filings or engagements.

Audit-Related Fees consist of fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Trust s financial statements. This category includes fees related to audit and attest services not required by statute or regulations and consultations concerning financial accounting and reporting standards.

Tax Fees consist of fees for professional services billed for tax compliance, tax advice and tax planning. These services include assistance regarding federal and state tax compliance, return preparation, preparation of the B-schedules and tax booklet.

All Other Fees consist of fees billed for products and services other than the services reported above.

The Trust has no directors or executive officers. Accordingly, the Trust does not have an audit committee and there are no audit committee pre-approval policies or procedures relating to services provided by the Trust s independent accountants. Pursuant to the terms of the Indenture, the Trustee engages and approves all services rendered by the Trust s independent accountants.

PART IV

ITEM 15. *EXHIBITS AND FINANCIAL STATEMENT SCHEDULES*

The following documents are filed as a part of this Annual Report on Form 10-K:

Financial Statements

Included in Part II of this Annual Report on Form 10-K:

Report of Independent Registered Public Accounting Firm

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	Description
4(a)	San Juan Basin Amended and Restated Royalty Trust Indenture, dated December 12, 2007 (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, which was amended and restated effective September 30, 2002), heretofore filed as Exhibit 99.2 to the Trust s Current Report on Form 8-K filed with the SEC on December 14, 2007, is incorporated herein by reference.*
4(b)	Net Overriding Royalty Conveyance from Southland Royalty Company to The Fort 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 on March 1, 2007, is incorporated herein by reference.*
4(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 filed with the SEC for the quarter ended September 30, 2002, is incorporated herein by reference.*
10	Indemnification Agreement, dated May 13, 2003, with effectiveness as of July 30, 2002, by and between Lee Ann Anderson and San Juan Basin Royalty Trust, heretofore filed as Exhibit 10(a) to the Trust s Quarterly Report on Form 10-Q filed with the SEC for the quarter ended March 31, 2003, is incorporated herein by reference.
13(a)	Registrant s Annual Report to Unit Holders for the fiscal year ended December 31, 2012.**
13(b)	Registrant s Quarterly Report on Form 10-Q filed with the SEC for the quarter ended March 31, 2012, is incorporated herein by reference.*
23	Consent of Cawley, Gillespie & Associates, Inc., reservoir engineer.**
31	Certification required by Rule 13a-14(a), dated March 1, 2013, by Lee Ann Anderson, Vice President and Senior Trust Officer of Compass Bank, the Trustee of the Trust.**
32	Certification required by Rule 13a-14(b), dated March 1, 2013, by Lee Ann Anderson, Vice President and Senior Trust Officer of Compass Bank on behalf of Compass Bank, the Trustee of the Trust.***
99.1	Independent Petroleum Engineers Report prepared by Cawley, Gillespie & Associates, Inc., dated March 1, 2013.**

* A copy of this Exhibit is available to any Unit Holder (free of charge) upon written request to the Trustee, Compass Bank, 300 W. 7th St., Suite B, Fort Worth, Texas 76102.

** Filed herewith.

*** Furnished 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.

SAN JUAN BASIN ROYALTY TRUST

By: COMPASS BANK, AS TRUSTEE OF THE SAN JUAN BASIN ROYALTY TRUST

By: /s/ Lee Ann Anderson
Lee Ann Anderson
Vice President and Senior Trust Officer

Date: March 1, 2013

(The Trust has no directors or executive officers)

EXHIBIT INDEX

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