San Juan Basin Royalty Trust (SJT - 10.00)
Outperforming Operating Companies

Summary and Conclusion

The units of San Juan Basin Royalty Trust appear to have appreciation potential in addition to offering high current income with inflation protection and tax advantage. A more conservative investment, units of the trust delivered a higher total return to investors in the past decade than any operating company among the 20 largest U.S. independent exploration and production stocks trading at the beginning of the period. The 1990s were a tough time for U.S. independents and we hope the 2000s will be better. If management can once again add value, operating companies may do better than the unmanaged trust. Yet in a more positive industry environment, the trust would do quite well also. Among the risks in the trust are fluctuations in distributions and the incentive for the operator of the properties, **Burlington Resources**, to put its interests ahead of those of the unitholders.

Present Value Discounts Future Cash Flows

Our calculations give a present value of the trust's reserves of $10.10 a unit (see file Sjt0128.xls, tab Asset Value). We explain the calculations following the columns from left to right.

<u>Volume Projections Anticipate Decline and Enhancement</u>

Natural gas production from existing producing wells is projected to decline at 9% per year for 30 years cumulating to a little more than 10 times 1999 production (see Table SJT-1). Those numbers ought to be conservative as production in the San Juan Basin, the home of all of the trust's production, has traditionally declined at some 7% per year. Moreover production could likely continue beyond 30 years.

Meanwhile the operators of San Juan gas production have almost continually been reinvesting in new wells, recompletions in old wells, fracturing and other steps to develop new production. The trust does not get specific information as to operator's plans for new spending for more than a year ahead. We project a 7% per year enhancement to production stemming the decline to a net 2%. That could be conservative also as Burlington Resources, the largest operator in the basin, has seen generally rising production for the past decade and plans continued investment in new capacity.

Enhancement adds 260 bcf of production in 30 years to the 309 bcf from existing capacity. The total of 569 bcf is 19 times 1999 production, not a conservative number in the context of proven reserves. Yet in light of the history of the basin and in view of specific sources of untapped potential the projection seems reasonable in economic value.

Price Projection Matches Inflation

After 2000, natural gas price escalates at 3% per year, only slightly more than the 2.1% per year implied by the difference in yield for U.S. Treasury bonds and U.S. Treasury Inflation Protected Securities. Considering that demand for natural gas as a clean fuel is strong and that producers of the commodity have not earned an economic return on new investment for the past ten years, a case could be made that natural gas price should readjust upward. Yet the trend of commodity price has been weak in the high productivity, technologically super-charged economy of recent years.

Operating Cost Supportable and Development Cost Attractive

Operating cost at a quarter of revenue last year allows for strong cash flow. Yet the trustee must be vigilant in assuring that the operator's charges are reasonable.

In the past, Burlington Resources has talked about spending 25% of cash flow to keep production flat. To be more conservative, we are allowing for a 2 percent per year decline net of enhancement rather than a flat trend.

Tax Credits Available Through 2002

There are three years remaining of Non Conventional Fuel Source (NFS) tax credits worth some $0.48 per unit in future value. For wells drilled before year-end 1992, producers can claim a tax credit for production of coal bed methane. The San Juan Basin proved to be a prolific source of fuel and tax credits. While stimulating drilling initially, the credits are now having the perverse effect of postponing drilling. Producers do not want to risk diverting coal seam gas from wells that generate tax credits. After 2002 when no more tax credits will be generated, there may be stepped up infill drilling to the coal seam. That drilling will add some to total recovery and also speed up recovery already anticipated.

Discount at 8% Per Year

Finally we multiply annual cash flows by the discount factor and add them up to derive present value. The discount factor is the discount rate applied for the appropriate time period. For the year 2000, the discount rate of 8% is applied for a half year, assuming that all the cash flow is received at mid year. For the year 2001, the rate is applied for a year and a half and so on. The rate represents a premium to the “risk-free” government rate, but is not as high as would be paid by low-grade borrowers.

Sensitivity Illustrates Upside

It is no surprise that current stock price reflects conventional knowledge about the future. What if conditions were different than those projected? For example, suppose existing production declines at 7% rather than 9% as we project for the trust. Go to cell E5 in the present value model and type in 7. Press Enter and see cell M14 change from 10.10 to 12.30. Undo the change.

The trust is also a straightforward play on long-term natural gas price. Suppose overnight the expected price after 2000 would be $1.00 per mcf higher. Go to cell E17 and type in 3.11. Press Enter and see cell M14 change from 10.10 to 14.90. Undo the change.

Distributable Income Model Projects Stable Trend

After seeing a $0.24 payout for the fourth quarter 1999 and $0.09 per unit for January 2000, we project a slightly lower rate for the remainder of the year (see file Sjt0128.xls, tab Quarterly Income). Natural gas price softened in November and December before strengthening again in mid-January. Fourth-quarter natural gas price reported by the trust may be the highest for several quarters. Actually the futures market seems to be just as fickle as analysts in projecting prices.

By definition our price projection is that of the consensus, the futures market. The differential between Henry Hub, the pricing point for futures, and what the trust receives, is our estimate.

Our natural gas volume projection for 2000 incorporates a decline of 1% per quarter from 107 mmcfd for the fourth quarter 1999. We apply the same decline to coal gas as to conventional gas. For the basin as a whole, the trend might be better in conventional gas until 2003 and then temporarily better in coal gas. Patterns in the trust may lag those of the basin because Burlington Resources works first on those properties where it has a higher interest than its 25% in the trust's properties.

We may not know more about fourth quarter details until the trust files its 10-K annual report with the Securities and Exchange Commission. The deadline for filing is March 31. Meanwhile the next disclosures are the February and March distributions, along with some operating data, to be released around the 20th of the respective months.

The distributable income model is updated weekly for oil and gas futures prices, monthly for distributions and some operating information, quarterly for interim disclosure and annually for more complete disclosure. If distributions materialize along the lines of the projections, stock price need not rise for unitholders to receive an attractive return.

Kurt H. Wulff
January 31, 2000
781-237-3401

N.B. The original version of this analysis was posted on the site referenced in the footnote below in separate text and spreadsheet files. When combining the tables and text in the same document for belated posting on mcdep.com, the tables were converted to pdf pages. As a result the interactivity encouraged above under the heading "Sensitivity Illustrates Upside" only works on the files posted originally.

Table SJT-1
San Juan Basin Royalty Trust
Present Value

Volume Decline (%/yr):	9	Price Escalation (%/yr):	3
Volume Enhancement (%/yr):	7	Variable Cost (%):	12
Capex/Cash Flow (%):	24	Discount rate (%/yr):	8

Year	Basic (bcf)	Volume Enhanced (bcf)	Total (bcf)	Price ($/mcf)	Revenue ($mm)	Fixed Cost ($mm)	Var Cost ($mm)	Cap Ex ($mm)	Distribution ($mm)	Distribution ($/unit)	Tax Credit ($/unit)	Disc Factor	Present Value ($/unit)
Total 2000 through 2029													
	309	260	569	3.00	1710	224	205	184	1097	23.54	0.48	0.42	10.10
1999	30.3		30.3	1.76	53.2	7.1	6.4	7.9	31.8	0.68	0.16		
2000	27.8	1.1	28.9	2.11	61.0	7.5	7.3	9.0	37.2	0.80	0.16	0.96	0.92
2001	25.3	3.0	28.3	2.18	61.6	7.5	7.4	11.2	35.5	0.76	0.16	0.89	0.82
2002	23.2	4.7	27.9	2.24	62.6	7.5	7.5	11.4	36.2	0.78	0.16	0.82	0.77
2003	21.3	6.3	27.5	2.31	63.6	7.5	7.6	11.6	36.9	0.79		0.76	0.60
2004	19.5	7.6	27.2	2.38	64.6	7.5	7.7	11.8	37.5	0.80		0.71	0.57
2005	17.9	8.8	26.8	2.45	65.5	7.5	7.9	12.0	38.2	0.82		0.65	0.54
2006	16.4	9.9	26.4	2.52	66.5	7.5	8.0	12.2	38.8	0.83		0.61	0.50
2007	15.1	10.9	26.0	2.60	67.4	7.5	8.1	12.4	39.4	0.85		0.56	0.47
2008	13.8	11.7	25.5	2.68	68.3	7.5	8.2	12.6	40.0	0.86		0.52	0.45
2009	12.7	12.4	25.1	2.76	69.3	7.5	8.3	12.8	40.7	0.87		0.48	0.42
2010	11.6	13.1	24.7	2.84	70.2	7.5	8.4	13.0	41.3	0.89		0.45	0.39
2011	10.7	13.6	24.3	2.92	71.1	7.5	8.5	13.2	41.9	0.90		0.41	0.37
2012	9.8	14.1	23.9	3.01	72.0	7.5	8.6	13.4	42.5	0.91		0.38	0.35
2013	9.0	14.5	23.5	3.10	72.9	7.5	8.7	13.6	43.1	0.92		0.35	0.33
2014	8.2	14.9	23.1	3.19	73.8	7.5	8.9	13.8	43.7	0.94		0.33	0.31
2015	7.6	13.5	21.1	3.29	69.4	7.5	8.3		53.6	1.15		0.30	0.35
2016	6.9	12.3	19.2	3.39	65.2	7.5	7.8		49.9	1.07		0.28	0.30
2017	6.4	11.2	17.6	3.49	61.3	7.5	7.4		46.5	1.00		0.26	0.26
2018	5.8	10.2	16.0	3.60	57.6	7.5	6.9		43.3	0.93		0.24	0.22
2019	5.4	9.3	14.6	3.70	54.2	7.5	6.5		40.2	0.86		0.22	0.19
2020	4.9	8.4	13.4	3.81	50.9	7.5	6.1		37.4	0.80		0.21	0.17
2021	4.5	7.7	12.2	3.93	47.9	7.5	5.7		34.7	0.74		0.19	0.14
2022	4.1	7.0	11.1	4.05	45.0	7.5	5.4		32.2	0.69		0.18	0.12
2023	3.8	6.4	10.2	4.17	42.3	7.5	5.1		29.8	0.64		0.16	0.10
2024	3.5	5.8	9.3	4.29	39.8	7.5	4.8		27.6	0.59		0.15	0.09
2025	3.2	5.3	8.5	4.42	37.4	7.5	4.5		25.5	0.55		0.14	0.08
2026	2.9	4.8	7.7	4.55	35.2	7.5	4.2		23.5	0.50		0.13	0.07
2027	2.7	4.4	7.1	4.69	33.1	7.5	4.0		21.7	0.46		0.12	0.06
2028	2.5	4.0	6.4	4.83	31.1	7.5	3.7		19.9	0.43		0.11	0.05
2029	2.3	3.6	5.9	4.98	29.2	7.5	3.5		18.3	0.39		0.10	0.04

Table SJT-2
San Juan Basin Royalty Trust
Distributable Income Model

	Year 1998	*Q1 3/31/99*	*Q2 6/30/99*	*Q3 9/30/99*	*Q4E 12/31/99*	*Year 1999E*	*Q1E 3/31/00*	*Q2E 6/30/00*	*Q3E 9/30/00*	*Q4E 12/31/00*	*Year 2000E*
Highlights											
Revenue ($mm) (75%)	54.3	12.1	10.8	13.0	17.4	53.2	14.5	15.7	15.3	15.4	61.0
Cash flow ($mm) (75%)	39.9	8.8	7.5	9.9	13.4	39.6	11.1	12.2	11.8	11.9	47.0
Per unit	0.86	0.19	0.16	0.21	0.29	0.85	0.24	0.26	0.25	0.26	1.01
Tax credit ($mm)	7.8	1.9	1.4	1.9	2.3	7.5	1.9	1.4	1.9	2.3	7.5
Per unit	0.17	0.04	0.03	0.04	0.05	0.16	0.04	0.03	0.04	0.05	0.16
Distributable Income ($mm)	29.6	6.8	5.9	7.8	11.3	31.8	8.6	9.7	9.4	9.5	37.2
Per unit	0.64	0.15	0.13	0.17	0.24	0.68	0.19	0.21	0.20	0.20	0.80
Units (millions)	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6	46.6
Volume											
Natural gas (mmbtu)											
Conventional		7.3	7.4	5.5	6.7	26.9	6.5	6.3	6.4	6.4	25.7
Coal Seam		3.7	3.8	3.3	3.5	14.4	3.5	3.4	3.4	3.4	13.8
Total		11.0	11.2	8.8	10.3	41.3	10.1	9.7	9.9	9.8	39.4
Conventional (btu/cf)		1,194	1,196	1,006	1,159	1,142	1,142	1,142	1,142	1,142	1,142
Coal Seam (btu/cf)		881	881	881	881	881	881	881	881	881	881
Natural gas (bcf)											
Conventional		6.1	6.2	5.5	5.8	23.5	5.7	5.6	5.6	5.6	22.5
Coal Seam		4.2	4.3	3.8	4.0	16.4	4.0	3.9	3.9	3.9	15.6
Total	41.5	10.3	10.5	9.3	9.8	39.9	9.7	9.4	9.5	9.4	38.1
Natural Gas (mmcfd)	113.7	112.4	118.4	100.6	106.7	109.4	105.6	104.6	103.5	102.5	104.1
Days	365	92	89	92	92	365	92	90	92	92	366
Oil (mb)	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1
Oil (mbd)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Days	366	92	89	92	92	364	92	90	92	92	366
Total gas & oil (bcf)	42.0	10.4	10.6	9.4	9.9	40.4	9.8	9.5	9.6	9.5	38.5
Price											
Natural gas ($/mmbtu) (Hubs lagged two months)											
Henry Hub ($/mmbtu)		1.87	1.89	2.27	2.66	2.17	2.36	2.57	2.51	2.54	2.50
Blanco Hub ($/mmbtu)		1.78	1.68	2.02	2.46	1.98					
SJT Conventional		1.48	1.29	2.09	2.27	1.75	1.96	2.17	2.11	2.14	2.09
SJT Coal Seam		1.38	1.20	1.65	2.13	1.58	1.76	1.97	1.91	1.94	1.89
Total		1.45	1.26	1.93	2.22	1.69	1.89	2.10	2.04	2.07	2.02
Natural gas ($/mcf)											
Conventional		1.77	1.54	2.11	2.63	2.00	2.24	2.48	2.40	2.45	2.39
Coal Seam		1.22	1.06	1.45	1.88	1.39	1.55	1.74	1.68	1.71	1.67
Total	1.72	1.54	1.34	1.84	2.32	1.75	1.95	2.18	2.11	2.15	2.10
Oil ($/bbl) (WTI Cushing lagged two months)											
WTI Cushing		12.25	14.67	18.57	22.59	17.02	26.06	26.92	24.92	23.33	25.31
SJT	13.29	9.65	12.72	15.71	17.50	13.99	22.06	22.92	20.92	19.33	21.30
Total gas & oil ($/mcf)		1.54	1.35	1.85	2.33	1.76	1.97	2.20	2.12	2.16	2.11
Revenue ($mm)											
Natural Gas - Conventional		10.8	9.6	11.5	15.2	47.1	12.8	13.8	13.5	13.6	53.7
Coal Seam		5.2	4.6	5.5	7.6	22.8	6.2	6.7	6.6	6.6	26.1
Total	71.2	16.0	14.1	17.0	22.8	69.9	19.0	20.5	20.1	20.2	79.8
Oil	1.1	0.2	0.2	0.3	0.4	1.1	0.4	0.4	0.4	0.4	1.6
Total	72.3	16.1	14.4	17.3	23.2	71.0	19.4	20.9	20.5	20.6	81.4
Cost ($mm)											
Severance tax	7.5	1.7	1.5	1.8	2.4	7.3	2.0	2.2	2.1	2.1	8.4
Operating	11.6	2.8	2.8	2.2	2.9	10.8	2.6	2.5	2.6	2.5	10.3
Total	19.1	4.5	4.3	4.0	5.3	18.1	4.6	4.7	4.7	4.7	18.7
Cash flow ($mm)	53.3	11.7	10.0	13.3	17.9	52.8	14.8	16.2	15.8	15.9	62.7
Development	12.8	2.3	3.0	2.7	2.6	10.6	3.0	3.0	3.0	3.0	12.0
Net proceeds ($mm)	40.4	9.4	7.1	10.5	15.3	42.3	11.8	13.2	12.8	12.9	50.7
Royalty income ($mm)	30.3	7.0	5.3	7.9	11.5	31.7	8.8	9.9	9.6	9.7	38.0
Royalty/Net proceeds	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
Administration	0.7	0.3	0.2	0.1	0.2	0.8	0.2	0.2	0.2	0.2	0.8
One-time			0.9			0.9					-
Distributable income ($mm)	29.6	6.8	5.9	7.8	11.3	31.8	8.6	9.7	9.4	9.5	37.2
Modeling ratios											
Severance tax/revenue	10.3%	10.3%	10.2%	10.4%	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%	10.3%
Operating cost ($/mcf)	0.28	0.27	0.27	0.24	0.29	0.27	0.27	0.27	0.27	0.27	0.27