Hugoton Royalty Trust (HGT - 8.75)
New Entity Created by Experienced Management

Summary and Conclusion

The units of Hugoton Royalty Trust appear to have appreciation potential in addition to offering high current income with inflation protection and tax advantage. Trading in the stock market for less than a year, the trust was formed by the management of Cross Timbers Oil Company who were also involved in the birth of **San Juan Basin Royalty Trust** and **Cross Timbers Royalty Trust**. Moreover the trust has about 30% of its reserves adjacent to those of **Dorchester Hugoton, Ltd**. thereby having similar deeper drilling potential. Remaining reserves are nearly equally divided between the Anadarko Basin in Oklahoma and the Green River Basin in Wyoming. Financial risk is low because the trust has no debt. The sponsoring company retains 57% of the units for eventual sale and enhanced liquidity for all unitholders.

Present Value Discounts Future Cash Flows

Our calculations give a present value of the trust's reserves of $12.60 a unit (see file Hgt0128.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 10% per year for 30 years cumulating to a little more than 10 times 1999 production (see Table HGT-1). Cross Timbers spend heavily to build production from the properties before the trust was formed. As result there is little history for much of the production.

We project an 8% per year enhancement to production stemming the decline to a net 2%. Enhancement adds 314 bcf of production in 30 years to the 300 bcf from existing capacity.

The total of 614 bcf is 21 times 1999 production, not a conservative number in the context of proven reserves. More history will give us more confidence in volume projections.

<u>Price Projection Matches Inflation</u>

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 Costs Higher

Operating costs at a third of revenue last year compared to closer to a quarter of revenue for San Juan Basin Royalty Trust and Dorchester Hugoton, Ltd. That makes present value somewhat more sensitive to natural gas price.

Projecting enhancement spending at 25 percent of cash flow leads to higher levels of spending than the $12 million per year on the underlying properties indicated in the trust offering document. We have in mind a rule of thumb that spending at 25 percent of cash flow from high-quality properties might keep production flat. To be more conservative, we are allowing for a 2 percent per year decline 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 $0.06 per unit in future value. Rather than for production of coal bed methane, the trust earns its tax credits for production from "tight sands".

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 midyear. 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 8% rather than 10% as we project for the trust. Go to cell E5 in the present value model and type in 8. Press Enter and see cell M14 change from 12.60 to 15.50. Undo the change.

The trust is also a straightforward play on long-term natural gas price. Suppose overnight the expected price for 2000 would be $1.00 per mcf higher. Go to cell E17 and type in 3.36. Press Enter and see cell M14 change from 12.60 to 18.50. Undo the change.

Distributable Income Model Projects Stable Trend

After seeing a $0.30 payout for the fourth quarter 1999 and $.10 per unit for January 2000, we project a slightly lower rate for the remainder of the year (see file Hgt0128.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 in projecting prices as are analysts.

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.

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 the case should be strong for appreciation in stock price.

Our natural gas volume projection for 2000 incorporates a decline of 1% per quarter from 104 mmcfd for the fourth quarter 1999. Our oil volume projection is similar.

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.

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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 HGT-1
Hugoton Royalty Trust
Present Value

Volume Decline (%/yr):	10		Price Escalation (%/yr):	3
Volume Enhancement (%/yr):	8		Variable Cost (%):	16
Capex/Cash Flow (%):	24		Discount rate (%/yr):	8

Year	Volume 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													
	300	314	614	3.32	2040	312	326	210	1192	29.80	0.06	0.42	12.60
1999	29.2		29.2	2.16	63.1	10.9	10.1	9.1	33.1	0.83	0.02		
2000	29.2	2.5	31.7	2.36	74.6	10.4	11.9	9.6	42.7	1.07	0.02	0.96	1.05
2001	26.3	4.8	31.1	2.43	75.3	10.4	12.1	12.7	40.2	1.00	0.02	0.89	0.91
2002	23.9	6.8	30.7	2.50	76.6	10.4	12.3	13.0	41.0	1.03	0.02	0.82	0.86
2003	21.7	8.5	30.3	2.57	77.9	10.4	12.5	13.2	41.8	1.05		0.76	0.80
2004	19.8	10.1	29.9	2.65	79.2	10.4	12.7	13.5	42.6	1.07		0.71	0.75
2005	18.0	11.5	29.4	2.73	80.4	10.4	12.9	13.7	43.4	1.09		0.65	0.71
2006	16.3	12.7	29.0	2.81	81.6	10.4	13.1	14.0	44.2	1.10		0.61	0.67
2007	14.8	13.7	28.6	2.90	82.8	10.4	13.2	14.2	45.0	1.12		0.56	0.63
2008	13.5	14.7	28.2	2.98	84.0	10.4	13.4	14.4	45.7	1.14		0.52	0.59
2009	12.3	15.4	27.7	3.07	85.2	10.4	13.6	14.7	46.5	1.16		0.48	0.56
2010	11.2	16.1	27.3	3.16	86.3	10.4	13.8	14.9	47.2	1.18		0.45	0.53
2011	10.1	16.7	26.8	3.26	87.4	10.4	14.0	15.1	47.9	1.20		0.41	0.49
2012	9.2	17.2	26.4	3.36	88.6	10.4	14.2	15.4	48.6	1.22		0.38	0.46
2013	8.4	17.6	25.9	3.46	89.7	10.4	14.4	15.6	49.4	1.23		0.35	0.44
2014	7.6	17.9	25.5	3.56	90.8	10.4	14.5	15.8	50.1	1.25		0.33	0.41
2015	6.9	16.1	23.0	3.67	84.4	10.4	13.5		60.5	1.51		0.30	0.46
2016	6.3	14.5	20.8	3.78	78.5	10.4	12.6		55.6	1.39		0.28	0.39
2017	5.7	13.0	18.8	3.89	73.0	10.4	11.7		50.9	1.27		0.26	0.33
2018	5.2	11.7	16.9	4.01	67.9	10.4	10.9		46.6	1.17		0.24	0.28
2019	4.7	10.6	15.3	4.13	63.1	10.4	10.1		42.6	1.07		0.22	0.24
2020	4.3	9.5	13.8	4.25	58.7	10.4	9.4		38.9	0.97		0.21	0.20
2021	3.9	8.6	12.5	4.38	54.6	10.4	8.7		35.5	0.89		0.19	0.17
2022	3.6	7.7	11.2	4.51	50.8	10.4	8.1		32.2	0.81		0.18	0.14
2023	3.2	6.9	10.2	4.65	47.2	10.4	7.6		29.3	0.73		0.16	0.12
2024	2.9	6.2	9.2	4.79	43.9	10.4	7.0		26.5	0.66		0.15	0.10
2025	2.7	5.6	8.3	4.93	40.8	10.4	6.5		23.9	0.60		0.14	0.08
2026	2.4	5.0	7.5	5.08	38.0	10.4	6.1		21.5	0.54		0.13	0.07
2027	2.2	4.5	6.8	5.23	35.3	10.4	5.7		19.3	0.48		0.12	0.06
2028	2.0	4.1	6.1	5.39	32.8	10.4	5.3		17.2	0.43		0.11	0.05
2029	1.8	3.7	5.5	5.55	30.5	10.4	4.9		15.3	0.38		0.10	0.04

Table HGT-2
Hugoton Royalty Trust
Distributable Income Model

	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 ($mm) (80%)	9.4	16.6	16.8	20.4	63.1	17.9	19.5	18.6	18.6	74.6
Cash flow ($mm) (80%)	5.1	11.1	11.5	14.5	42.3	12.4	13.9	13.1	13.1	52.6
Per unit	0.13	0.28	0.29	0.36	1.06	0.31	0.35	0.33	0.33	1.31
Tax credit ($mm)	0.2	0.2	0.2	0.2	0.8	0.2	0.2	0.2	0.2	0.8
Per unit	0.01	0.01	0.01	0.01	0.02	0.01	0.01	0.01	0.01	0.02
Distributable Income ($mm)	3.6	8.8	8.5	12.2	33.1	10.0	11.4	10.7	10.7	42.7
Per unit	0.09	0.22	0.21	0.30	0.83	0.25	0.28	0.27	0.27	1.07
Units (millions)	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
Volume										
Natural Gas (bcf)	5.5	9.6	9.5	9.6	34.2	9.4	9.3	9.3	9.2	37.2
Natural Gas (mmcfd)	89.0	107.6	103.4	104.2	102.1	103.4	102.4	101.4	100.4	101.9
Days	62	89	92	92	335	91	91	91	91	365
Oil (mb)	66	115	104	104	389	101	101	101	100	403
Oil (mbd)	1.1	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Days	62	96	92	92	342	90	91	92	92	365
Total (bcf)	5.9	10.3	10.1	10.2	36.5	10.0	9.9	9.9	9.8	39.6
Price										
Natural Gas (HH lagged two months)										
Henry Hub ($/mmbtu)	1.78	1.89	2.27	2.66	2.18	2.36	2.57	2.51	2.54	2.50
HGT ($/mcf)	2.00	2.00	2.01	2.42	2.12	2.11	2.32	2.26	2.29	2.24
Oil ($/bbl) (WTI Cushing lagged two months)										
WTI Cushing	11.90	14.67	18.57	22.59	17.39	26.06	26.92	24.92	23.33	25.31
HGT	10.86	13.64	18.18	21.59	16.51	25.06	25.92	23.92	22.33	24.31
Total ($/mcf)	1.99	2.02	2.07	2.49	2.16	2.23	2.45	2.36	2.38	2.36
Revenue ($mm)										
Natural Gas	11.0	19.1	19.1	23.2	72.5	19.9	21.7	20.9	21.0	83.5
Oil	0.7	1.6	1.9	2.2	6.4	2.5	2.6	2.4	2.2	9.8
Total	11.7	20.7	21.0	25.5	78.9	22.4	24.3	23.3	23.2	93.3
Cost ($mm)										
Tax, transport & other	1.4	2.1	2.1	2.5	8.2	2.2	2.4	2.3	2.3	9.3
Production	2.3	2.9	2.8	3.0	11.0	2.9	2.9	2.9	2.8	11.5
Overhead	1.6	1.7	1.8	1.7	6.9	1.7	1.7	1.7	1.7	6.7
Total	5.3	6.8	6.6	7.3	26.1	6.9	7.0	6.9	6.8	27.5
Cash flow ($mm)	6.4	13.9	14.4	18.2	52.9	15.6	17.3	16.4	16.4	65.7
Development	2.0	2.8	3.7	2.8	11.3	3.0	3.0	3.0	3.0	12.0
Net proceeds ($mm)	4.5	11.1	10.7	15.3	41.6	12.6	14.3	13.4	13.4	53.7
Royalty income ($mm)	3.6	8.9	8.5	12.3	33.2	10.0	11.5	10.7	10.7	43.0
Royalty/Net proceeds	80%	80%	80%	80%	80%	80%	80%	80%	80%	80%
Administration	0.0	0.0	0.0	0.1	0.2	0.1	0.1	0.1	0.1	0.3
Distributable income ($mm)	3.6	8.8	8.5	12.2	33.1	10.0	11.4	10.7	10.7	42.7
Modeling ratios										
Tax and other/revenue	12%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Production cost ($/mcf)	0.39	0.29	0.28	0.29	0.30	0.29	0.29	0.29	0.29	0.29
Overhead cost ($/mcf)	0.28	0.17	0.17	0.17	0.19	0.17	0.17	0.17	0.17	0.17

Note: The trust was formed on December 1, 1998. Also there is a two month lag between actual and reported production.
As a result, the first quarter of operations includes only the two months of December 1998 and January 1999.