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Freehold
ROYALTY TRUST

NEWS RELEASE

TSX: FRU.UN

Freehold Royalty Trust Announces Third Quarter Results; Declares Extra Distribution

CALGARY, Alberta/November 10, 2004/CCN/ - Freehold Royalty Trust today announced results for the third quarter ended September 30, 2004.

THIRD QUARTER HIGHLIGHTS

- Acquired outstanding shares of Ventana Ventures Inc. for $3.0 million, adding 60 barrels of oil equivalent (boe) per day of royalty production
- Production averaged 5,447 boe per day, down 8% compared with the third quarter of 2003
- Price realizations averaged $40.96 per boe, up 27% from the third quarter of 2003
- Operating netback rose 29% over the third quarter last year to average $36.85 per boe
- Distributions totalled $0.47 per Trust Unit, up 18% from the third quarter of 2003
- An extra distribution of $0.13 per Trust Unit related to the third quarter will be paid on December 15, 2004, along with the regular monthly distribution of $0.12 (total $0.25 per Trust Unit – record date November 30, 2004, ex-distribution date November 26, 2004)

Freehold achieved substantial gains in revenue, funds generated from operations (cash flow) and net income relative to the third quarter last year. Commodity prices remained near record highs throughout the quarter, although the price differential between light and heavy crude oil continued to widen significantly. Results for the year to date were also solid, but were lower than last year, mainly due to record high natural gas prices in the first quarter of 2003 and a stronger Canadian dollar this year. As we do not have any commodity or foreign currency hedges in place, our results reflect the net effect of higher commodity prices and a higher Canadian dollar, relative to last year.

RESULTS AT A GLANCE	Three Months Ended September 30 **2004**	2003	% Change	Nine Months Ended September 30 **2004**	2003	% Change
Financial						
Gross revenue ($000s)	**20,726**	17,688	+17	**58,555**	57,297	+2
Net income[1] ($000s)	**10,306**	8,868	+16	**27,495**	31,131	-12
Per Trust Unit ($)	**0.33**	0.28	+18	**0.87**	1.00	-13
Distributions to Unitholders ($000s)	**14,808**	12,545	+18	**39,041**	40,574	-4
Per Trust Unit[2] ($)	**0.47**	0.40	+18	**1.24**	1.30	-5
Long-term debt ($000s)	**17,000**	17,500	-3	**17,000**	17,500	-3
Trust Units outstanding	**31,521,736**	31,431,736	-	**31,521,736**	31,431,736	-
Weighted average	**31,499,481**	31,335,024	+1	**31,477,064**	31,073,906	+1
Operating						
Average daily production						
Oil (bbls/d)	**3,474**	3,781	-8	**3,565**	3,671	-3
NGLs (bbls/d)	**274**	338	-19	**278**	325	-14
Natural gas (mcf/d)	**10,191**	10,745	-5	**10,502**	11,030	-5
Oil equivalent (boe/d)	**5,447**	5,909	-8	**5,593**	5,834	-4
Average price realizations ($/boe)	**40.96**	32.15	+27	**37.76**	35.50	+6
Operating netback ($/boe)	**36.85**	28.61	+29	**33.85**	32.05	+6

1 2003 restated.
2 Based on the number of Trust Units issued and outstanding at each record date.

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

The following discussion is management's opinion about Freehold Resources Ltd. and Freehold Royalty Trust's (the "Trust") (collectively "Freehold"), operating and financial results for the three months ended September 30, 2004 and previous periods, and the outlook for Freehold based on information available as at November 10, 2004. The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended September 30, 2004 and September 30, 2003 and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion should be read in conjunction with the Trust's annual MD&A and audited combined financial statements for the years ended December 31, 2003 and 2002, together with the accompanying notes. These are included on pages 15 through 44 of the Trust's 2003 annual report to Unitholders.

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at November 10, 2004, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. No assurance can be given that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. We disclaim any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

SUPPLEMENTAL DISCLOSURE

We believe that distributions to Unitholders, cash flow and netbacks are useful supplemental measures. You are cautioned that distributions to Unitholders should not be construed as an alternate to net income as determined by GAAP. Cash flow, as used in this report, refers to funds generated from operations derived from our Combined Statements of Cash Flows. Cash flow represents cash provided by operating activities, before changes in non-cash working capital. We use cash flow to analyze operating performance, leverage and liquidity. Operating netback, which is calculated as average unit sales price less royalties and operating expenses; and investor netback, which deducts administrative and interest expense and income and capital taxes, represent the cash margin for product sold, calculated on a per boe basis. Distributions to Unitholders, cash flow and netback do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measure for other entities.

CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). We use the international conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

RESULTS OF OPERATIONS

Financial results for the third quarter were the second best in the history of Freehold, buoyed by commodity prices at the high end of the historical range. Relative to the same period last year, we achieved gains in revenue, funds generated from operations (cash flow) and net income, despite lower production volumes. The table below is a summary of our performance for the third quarter of 2004 and the preceding seven quarters.

Quarterly Results	**2004**			2003				2002
($000s, except as noted)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Revenue, net of royalty expense	**19,994**	19,066	17,250	15,230	16,865	17,070	20,804	16,711
Funds generated from operations	**17,409**	16,428	14,380	12,691	14,714	14,922	18,365	14,495
Per Trust Unit ($)	**0.55**	0.52	0.46	0.40	0.47	0.48	0.60	0.48
Distributions to Unitholders	**14,808**	12,593	11,640	12,575	12,545	15,631	12,398	11,477
Per Trust Unit ($)	**0.47**	0.40	0.37	0.40	0.40	0.50	0.40	0.38
Payout ratio (%)	**85%**	77%	81%	99%	85%	105%	68%	79%
Net income[1]	**10,306**	9,515	7,674	5,947	8,868	9,334	12,929	7,324
Per Trust Unit, diluted ($)	**0.33**	0.30	0.24	0.19	0.28	0.30	0.42	0.24
Long-term debt	**17,000**	17,000	18,000	18,000	17,500	18,500	17,500	30,000
Daily production (boe/d)	**5,447**	5,757	5,577	5,768	5,909	5,746	5,847	6,033
Average selling price ($/boe)	**40.96**	37.37	35.00	29.51	32.15	33.49	40.97	31.27
Operating netback ($/boe)	**36.85**	33.57	31.18	25.88	28.61	30.47	37.18	28.08
U.S./Cdn.$ exchange rate	**0.7651**	0.7357	0.7590	0.7600	0.7247	0.7158	0.6626	0.6372
WTI crude oil (US$/bbl)	**43.88**	38.31	35.14	31.18	30.20	28.91	33.86	28.14
Bow River heavy oil (C$/bbl)	**41.96**	37.31	34.93	28.53	30.79	31.61	39.79	32.21
Light/heavy oil differential (C$/bbl)	**14.29**	13.29	10.67	11.02	10.13	9.51	11.16	10.60
AECO natural gas (C$/mcf)	**6.66**	6.80	6.61	5.59	6.29	6.99	7.92	5.46
Trading Performance TSX: FRU.UN								
High ($ per Trust Unit)	**16.97**	15.80	16.30	17.19	13.85	13.48	11,85	11.33
Low ($ per Trust Unit)	**14.57**	14.65	14.02	13.11	12.81	11.20	10.50	10.00
Close ($ per Trust Unit)	**16.25**	15.00	14.75	16.35	13.70	13.05	11.78	10.88
Volume (000s)	**1,768**	3,149	2,399	2,506	2,991	2,447	3,025	1,494

1 2002 and 2003 restated.

PRODUCTION

Production was down 8% quarter over quarter, due to normal production declines and production commencement delays caused by wet weather related access.

On a year-to-date basis, production from working interest wells increased 5%, mainly due to the successful 2003 drilling program at Hayter and a prior period adjustment, while royalty production declined 8%. Overall, average production declined 4% to 5,593 boe per day. In the absence of an acquisition in the fourth quarter, we expect our production to average slightly higher than this level for the remainder of the year. Our production profile is currently weighted 69% to oil and NGLs and 31% to natural gas.

Excluding unit wells, in which our interests are small, approximately 68% of wells drilled during the year have not yet been placed on production. These wells are expected to add to production volumes during the fourth quarter of 2004 and the first quarter of 2005.

Average Daily Production	Three Months Ended September 30 2004	2003	% Change	Nine Months Ended September 30 2004	2003	% Change
Royalty lands						
Oil (bbls/d)	**2,199**	2,424	-9	2,183	2,442	-11
NGLs (bbls/d)	**208**	252	-17	214	235	-9
Natural gas (mcf/d)	**7,501**	7,946	-6	7,953	8,214	-3
Oil equivalent (boe/d)	**3,657**	4,000	-9	3,722	4,046	-8
Working interest properties						
Oil (bbls/d)	**1,275**	1,357	-6	1,382	1,229	+12
NGLs (bbls/d)	**66**	86	-23	64	90	-29
Natural gas (mcf/d)	**2,690**	2,799	-4	2,549	2,816	-9
Oil equivalent (boe/d)	**1,789**	1,909	-6	1,871	1,788	+5
Total Trust						
Oil (bbls/d)	**3,474**	3,781	-8	3,565	3,671	-3
NGLs (bbls/d)	**274**	338	-19	278	325	-14
Natural gas (mcf/d)	**10,191**	10,745	-5	10,502	11,030	-5
Oil equivalent (boe/d)	**5,447**	5,909	-8	5,593	5,834	-4
Number of days in period (days)	**92**	92	-	274	273	-
Total volumes during period (mboe)	**501.1**	543.6	-8	1,532.5	1,592.6	-4
Potash (tonnes/d)	**5.2**	5.4	-4	7.3	7.6	-4

BENCHMARK PRICES

WTI crude oil prices climbed 45% in the third quarter and 26% for the year to date, compared with the same periods in 2003. Light/heavy oil differentials widened to $14.29 per barrel in the third quarter, up 41% from the third quarter last year and up 24% over the first nine months of 2003. The average price for Bow River heavy oil rose 36% in the third quarter and 12% in the first nine months of 2004. AECO natural gas prices rose 6% quarter over quarter but were 5% lower year over year.

Average Benchmark Prices	Three Months Ended September 30 2004	2003	% Change	Nine Months Ended September 30 2004	2003	% Change
WTI crude oil (US$/bbl)	**43.88**	30.20	+45	**39.11**	30.99	+26
Bow River heavy oil (C$/bbl)	**41.96**	30.79	+36	**38.07**	34.06	+12
Light/heavy oil differential	**14.29**	10.13	+41	**12.75**	10.27	+24
AECO natural gas (C$/mcf)	**6.66**	6.29	+6	**6.69**	7.07	-5
U.S./Cdn. $ exchange rate	**0.7651**	0.7247	+6	**0.7533**	0.7010	+7

REALIZED PRICES

As oil and gas prices are denominated in U.S. dollars, realized selling prices in Canadian dollars are influenced by currency exchange rates. In the first nine months of 2004, the Canadian dollar averaged U.S. $0.7533, five cents higher than a year ago, reducing Canadian dollar price realizations. The Canadian dollar has continued to gain strength and is expected to remain strong in 2005.

Compared with last year, our average selling price rose 27% in the third quarter and 6% for the year to date. The increase in light/heavy oil differential prices resulted in a lower average price for our production relative to the benchmark WTI price. The differential is significant for Freehold, as approximately 36% of our total boe production is heavy oil.

Average Selling Prices	Three Months Ended September 30 2004	2003	% Change	Nine Months Ended September 30 2004	2003	% Change
Oil ($/bbl)	**43.19**	31.37	+38	**38.08**	34.20	+11
NGLs ($/bbl)	**40.08**	28.91	+39	**36.09**	31.40	+15
Oil and NGLs ($/bbl)	**42.97**	31.17	+38	**37.94**	33.98	+12
Natural gas ($/mcf)	**6.09**	5.73	+6	**6.23**	6.47	-4
Oil equivalent ($/boe)	**40.96**	32.15	+27	**37.76**	35.50	+6
Potash ($/tonne)	**174.14**	122.66	+42	**161.37**	130.64	+24

REVENUE

Gross revenue of $20.7 million for the third quarter of 2004 was up 17% from a year ago, as higher prices more than offset lower production volumes. Year-to-date, gross revenue increased 2%. We receive revenue from more than 200 industry operators. The accompanying table demonstrates the net effect of price and volume variances on gross revenues.

Gross Revenue Variances ($000s)	Three Months Ended September 30 2004 vs. 2003	2003 vs. 2002	Nine Months Ended September 30 2004 vs. 2003	2003 vs. 2002
Oil and NGLs				
Production increase (decrease)	**(1,460)**	(156)	**(1,438)**	(1,731)
Price increase (decrease)	**4,468**	(1,096)	**4,323**	3,957
Net increase (decrease)	**3,008**	(1,252)	**2,885**	2,226
Natural gas				
Production increase (decrease)	**(310)**	130	**(832)**	283
Price increase (decrease)	**352**	2,357	**(733)**	9,065
Net increase (decrease)	**42**	2,487	**(1,565)**	9,348
Other	**(12)**	(49)	**(62)**	141
Gross revenue increase (decrease)	**3,038**	1,186	**1,258**	11,715

ROYALTIES PAID

We incur royalty expenses relating to ownership in working interest production. These expenses are tied directly to commodity prices and production volumes. Quarter over quarter, royalty expenses were 4% lower (on a per boe basis) and for the nine months ended September 30, 2004, royalty expenses declined 9%. Prior period adjustments relating to Crown natural gas royalties reduced royalty expenses in the third quarter by approximately $100,000 ($0.20 per boe).

Royalty Expenses (net of ARC)	Three Months Ended September 30 2004	2003	% Change	Nine Months Ended September 30 2004	2003	% Change
Working interest properties ($000s)	**732**	823	-11	**2,245**	2,558	-12
Per boe ($)	**4.44**	4.69	-5	**4.38**	5.24	-16
Total royalty expenses ($000s)	**732**	823	-11	**2,245**	2,558	-12
Total Trust[1] ($/boe)	**1.46**	1.52	-4	**1.46**	1.61	-9

1 We do not incur royalty expenses on production from our royalty lands. As the royalty owner, we receive the royalty as income from other companies.

OPERATING EXPENSES

Operating expenses on our working interest properties rose 17% from the third quarter of 2003 and were 20% higher than the first nine months of last year. Most of our working interest properties are operated by other parties. Prior period adjustments amounted to the majority of the increase. In addition, with industry activity at record levels, the demand for oilfield goods and services is intense and the energy sector has been experiencing rising costs.

Lower production volumes and the above explanations contributed to higher operating costs on a unit of production basis. For the total Trust, operating costs were $3.05 per boe for the third quarter and $2.90 per boe for the year to date, up 27% and 25% respectively, from the same periods last year.

	Three Months Ended September 30		%	Nine Months Ended September 30		%
Operating Expenses	**2004**	2003	Change	**2004**	2003	Change
Working interest properties ($000s)	**1,530**	1,312	+17	**4,437**	3,688	+20
Per boe ($)	**9.29**	7.47	+24	**8.65**	7.56	+14
Total operating expenses ($000s)	**1,530**	1,312	+17	**4,437**	3,688	+20
Total Trust[1] ($/boe)	**3.05**	2.41	+27	**2.90**	2.32	+25

1 Freehold does not incur operating costs on its royalty lands.

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

G&A expenses for the third quarter of 2004 rose 26% from the same period in 2003. Year-to-date, G&A expenses were 19% higher, primarily due to increased staff levels and higher costs associated with regulatory compliance and financial reporting obligations. On a per boe basis, G&A costs were also higher, as production volumes were lower. Since we do not operate any of our royalty production, our overhead recoveries are minimal. While we incur expenses to administer our interests in more than 16,000 wells in western Canada, our G&A expenses are less than 5% of gross revenue.

	Three Months Ended September 30		%	Nine Months Ended September 30		%
G&A Expenses	**2004**	2003	Change	**2004**	2003	Change
G&A expenses ($000s)	**731**	580	+26	**2,638**	2,209	+19
Per boe ($)	**1.46**	1.07	+36	**1.72**	1.39	+24
As a percentage of gross revenue (%)	**3.5**	3.3	+6	**4.5**	3.9	+15

MANAGEMENT FEES

The Manager of the Trust receives 22,500 Trust Units per quarter as its management fee. The ascribed value of the management fee is based on the closing price of the Trust Units on the Toronto Stock Exchange at the end of each quarter. The increase in the dollar value of management fees directly reflects the price appreciation of the Trust Units between the two periods. The closing price of the Trust Units was $16.25 on September 30, 2004, versus $13.70 on September 30, 2003. The Manager also received a fee of $42,000 relating to acquisitions completed during the quarter.

Management Fees	Three Months Ended September 30		%	Nine Months Ended September 30		%
($000s, except as noted)	**2004**	2003	Change	**2004**	2003	Change
Management fees (paid in Trust Units)	**366**	308	+19	**1,035**	867	+19
Acquisition fees (1.5%)	**42**	4	+950	**47**	29	+62
Total	**408**	312	+31	**1,082**	896	+21
Per boe ($)	**0.81**	0.57	+42	**0.71**	0.56	+27
Trust Unit closing price	**16.25**	13.70	+19	**16.25**	13.70	+19

NETBACKS

Our operating netback rose 29% to $36.85 per boe, compared with the third quarter last year. Year-to-date, our operating netback was $33.85, up 6% from the prior period. These operating netbacks represent nearly 90% of gross revenue. We have consistently delivered a superior netback, relative to our peer group, as we do not incur royalty or operating expenses on our royalty lands.

Operating Netbacks ($/boe)	Three Months Ended September 30 **2004**	2003	% Change	Nine Months Ended September 30 **2004**	2003	% Change
Gross revenue[1]	**41.36**	32.54	+27	**38.21**	35.98	+6
Royalty expenses (net of ARC)	**1.46**	1.52	-4	**1.46**	1.61	-9
Operating expenses	**3.05**	2.41	+27	**2.90**	2.32	+25
Operating netback	**36.85**	28.61	+29	33.85	32.05	+6
As a percentage of gross revenue (%)	**89**	88	+1	89	89	-

1 Gross revenue includes potash revenue, sulphur revenue and other.

NET INCOME AND FUNDS GENERATED FROM OPERATIONS

The factors outlined above resulted in higher net income and funds generated from operations (cash flow) for the third quarter of 2004 but lower results for the year to date.

Net Income and Funds Generated from Operations ($000s, except as noted)	Three Months Ended September 30 **2004**	2003	% Change	Nine Months Ended September 30 **2004**	2003	% Change
Net income	**10,306**	8,868	+16	**27,495**	31,131	-12
Per Trust Unit ($)	**0.33**	0.28	+18	**0.87**	1.00	-13
Funds generated from operations	**17,409**	14,714	+18	**48,217**	48,001	-
Per Trust Unit ($)	**0.55**	0.47	+17	**1.53**	1.54	-1

DISTRIBUTIONS TO UNITHOLDERS

The level of distributions is closely related to the price we receive for our oil and gas production. Distributions for the third quarter of 2004 represented a payout of 85% of funds generated and were 18% higher than the same period last year. For the first nine months of 2004, distributions represented a payout of 81% of funds generated and were down 5% from last year. Funds withheld for capital expenditures, acquisitions, repayment of long term debt and improvements to working capital resulted in the lower payout ratio for the year to date.

Analysis of Distributions to Unitholders ($000s, except as noted)	Three Months Ended September 30 **2004**	2003	% Change	Nine Months Ended September 30 **2004**	2003	% Change
Funds generated from operations	**17,409**	14,714	+18	**48,217**	48,001	-
Deduct:						
Site reclamation fund contributions	**(103)**	(80)	+29	**(310)**	(238)	+30
Provision for capital expenditures	**(2,278)**	(2,200)	+4	**(3,928)**	(5,000)	-21
Debt additions (repayment)	**-**	201	-	**(1,000)**	(1,999)	-50
Property and royalty acquisitions	**(2,752)**	(292)	+842	**(3,082)**	(1,814)	+70
Working capital changes	**2,532**	202	+1,153	**(856)**	1,624	-153
Distributions to Unitholders	**14,808**	12,545	+18	**39,041**	40,574	-4
Per Trust Unit[1] ($)	**0.47**	0.40	+18	**1.24**	1.30	-5
Payout ratio[2] (%)	**85**	85	-	**81**	85	-5

1 Based on the number of Trust Units issued and outstanding at each record date.

2 Distributions to Unitholders as a percentage of funds generated from operations.

Regular monthly distributions are supplemented by extra distributions (quarterly top-ups) when excess income is available. The board of directors has declared an extra distribution of $0.13 per Trust Unit related to the third quarter. The distribution is payable on December 15, 2004 to Unitholders of record on November 30, 2004 (ex-distribution date November 26, 2004). Combined, the December 15th payment (regular monthly distribution of $0.12 and the $0.13 top-up for the third quarter), will total $0.25 per Trust Unit. Including the December 15th payment, the trailing 12-month-distributions paid totals $1.71 per Trust Unit. Since inception in November 1996, the Trust has distributed a total of $10.16 per Trust Unit.

On November 10, 2004, there were 31,521,736 Trust Units outstanding, unchanged from the balance outstanding at the end of the third quarter.

UNITHOLDER TAXATION

Due to continued high commodity prices, we currently estimate that, for residents of Canada, approximately 75% of distributions to Unitholders in 2004 will be taxable as other income and 25% will be a tax-deferred return of capital.

LIQUIDITY AND CAPITAL RESOURCES

At the end of the third quarter, we had no short-term debt outstanding and long-term debt was $17.0 million. We have approximately $48.0 million of available capacity under our credit facilities. The Trust's ratio of net debt (long-term debt less positive working capital) to trailing cash flow remains among the lowest in the energy trust sector, at 0.2:1. Our healthy financial condition gives us maximum flexibility to pursue opportunities to grow our asset base.

CAPITAL EXPENDITURES

The Trust's capital expenditure obligations are deducted from funds generated from operations, prior to the determination of distributions to Unitholders. As we do not incur any capital expenditures relating to our royalty properties, our capital requirements are modest, relative to most energy trusts. For our working interest properties, capital expenditures totalled $2.3 million in the third quarter and $3.9 million for the year to date. Our 2004 budget included $1.0 million for drilling activities at Pembina Cardium Unit No. 9, which has now been deferred until 2005. However increased development activity on Freehold's other working interest lands will more than offset this. Capital expenditures in the fourth quarter will be approximately $1.2 million. Capital expenditures in 2005 are estimated to be $5.1 million.

ACQUISITIONS

Effective July 31, 2004, Freehold acquired all of the outstanding shares of Ventana Ventures Inc., a private corporation for approximately $3.0 million (including $0.2 million working capital). The primary assets are royalty interests in oil and gas properties in the Peace River area of Alberta. The properties added approximately 60 boe per day of royalty production from the effective date of the acquisition.

CHANGE IN ACCOUNTING POLICIES

ASSET RETIREMENT OBLIGATIONS

On January 1, 2004, we adopted new Canadian accounting standards for asset retirement obligations. This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

We now recognize the fair value of an Asset Retirement Obligation (ARO) in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

Previously, we recognized a provision for estimated future abandonment and site restoration costs calculated on the unit-of-production method over the remaining proved reserves. The annual charge was expensed as provision for future site restoration, with abandonment and site restoration expenditures charged to the accumulated provision as incurred.

This change in accounting policy resulted in the following increases (decreases) to our 2003 financial results:

($000s)	September 30, 2003 (three months)	September 30, 2003 (nine months)	December 31, 2003 (year)
Net income	5	(5)	52
Petroleum and natural gas interests, net of accumulated depletion and depreciation	1,775	1,775	1,732
Asset retirement obligation	3,563	3,563	3,606
Provision for future site restoration	(1,630)	(1,630)	(1,773)

The opening adjustment to 2004 Unitholders' equity was a reduction of $101,000 (2003 - $153,000). This reflects the cumulative impact of accretion and depletion expense, net of the previously recorded cumulative site restoration provision.

We have no asset retirement obligations (ARO) on our royalty income properties. Our ARO results from our responsibility to abandon and reclaim our net share of all working interest properties. The net present value of our total ARO is estimated to be $3.8 million, with the undiscounted value being $9.6 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being over 15 years away. A credit adjusted, risk-free rate of 6.25% was used to calculate the present value of the ARO.

	September 30, 2004	December 31, 2003
Balance, beginning of period	$ 3,606	$ 3,289
Liabilities incurred	100	137
Liabilities settled	(43)	(34)
Accretion expense	172	214
Balance, end of period	$ 3,835	$ 3,606

PETROLEUM AND NATURAL GAS INTERESTS

On January 1, 2004, we adopted CICA Accounting Guideline 16, *Oil and Gas Accounting – Full Cost*. This guideline modifies the ceiling test calculation, requiring that an impairment loss be recognized when the carrying amount of assets is greater than the sum of the undiscounted cash flows. Our calculation, performed at January 1, 2004, resulted in no impairment loss. The future prices we used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for our quality, transportation, and contract differences.

DEVELOPMENT ACTIVITIES

ROYALTY LANDS

Industry-wide, 16,651 wells were drilled in western Canada during the first nine months of 2004, a 4% rise over last year and a new drilling record for the Canadian industry. In the third quarter, 6,272 wells were drilled, down 11% from last year's level as wet weather throughout the summer slowed the pace of drilling activity. However, industry forecasters anticipate a strong fourth quarter, with the total drilling count expected to surpass 21,000 wells by the end of the year.

Lessees drilled 112 wells (5.0 net) on our royalty lands in the third quarter, down slightly from 122 wells (6.3 net) in the third quarter of last year. These wells were drilled at no cost to Freehold. In the first nine months of this year, 525 (9.4 net) royalty wells were drilled, compared with 433 (12.9 net) in the same period last year. While the gross number of wells drilled is up significantly year over year, the net contribution is down. This relates to the location and type of wells being drilled, including a high number of shallow gas wells and unitized wells.

Currently 60 gross (2.0 net) drilling licences have been issued on our royalty lands. This is up from 34 gross (1.7 net) one year ago, signalling a very strong fourth quarter for royalty drilling.

Royalty Lands Drilling Summary	Three Months Ended September 30		%	Nine Months Ended September 30		%
(includes unitized wells)	**2004**	2003	Change	**2004**	2003	Change
Gross	**112**	122	-8	**525**	433	+21
Net royalty interest basis	**5.0**	6.3	-21	**9.4**	12.9	-27

WORKING INTEREST PROPERTIES

In the third quarter of 2004, we spent $2.3 million on facilities and the drilling of 15 (3.0 net) wells. This resulted in 2 (0.0 net) natural gas wells and 13 (3.0 net) oil wells, for a 100% success rate. The majority of this activity was at Hayter, where 11 (2.6 net) wells were drilled, all of which are currently producing.

Plans for the fourth quarter include increased water handling at Hayter. These initiatives will increase working interest production during the fourth quarter of 2004 and the first quarter of 2005. Other approved drilling is expected to marginally add to these volumes.

At Pembina Cardium Unit No. 9, the operator of the unit is focused on improving water injection into the pool to increase reservoir pressure and ultimately production and reserves.

Working Interest Properties Drilling Summary	Three Months Ended September 30				Nine Months Ended September 30			
	2004		2003		**2004**		2003	
	(gross)	**(net)**	(gross)	(net)	**(gross)**	**(net)**	(gross)	(net)
Oil	**13**	**3.0**	16	3.3	**23**	**3.3**	37	5.9
Natural gas	**2**	**0.0**	5	0.3	**26**	**0.5**	31	0.3
Total	**15**	**3.0**	21	3.6	**49**	**3.8**	68	6.2

OUTLOOK

Crude oil prices continue to be very strong. Demand remains robust, especially from China, and the outlook for 2005 is positive. World oil inventories remain tight and recent reports suggest OPEC will not be able to increase production significantly in the near term. Fears of a cold winter in the Northern Hemisphere and economic growth in China and India are adding to concerns about shortages of supplies amid disruptions to production in the Gulf of Mexico, Iraq, Venezuela, Nigeria, Russia and Norway.

Natural gas prices also remain strong. A colder than normal winter could push natural gas prices even higher as supply remains a major concern. U.S. gas storage levels are still behind those of last year and lower than the five-year average, while Canadian production is declining.

Although the Western Canadian Sedimentary Basin is maturing, drilling activity continues at a record pace. The latest forecast from the Canadian Association of Oilwell Drilling Contractors indicates that more than 21,000 wells will be completed this year, which would top the record set in 2003. The CAODC estimates that 2005 will outpace this year's activity by as many as 3,000 wells, which would be a 13% increase over 2004. We expect that drilling on our royalty lands would likewise be at high levels.

The energy trust sector continues to exhibit strong market performance, as low interest rates and a lack of income-generating investment alternatives continue to attract investors. However, rising interest rates in 2005 would put downward pressure on unit prices.

The acquisition market remains extremely competitive, although strong commodity prices have resulted in high transaction prices. We continue to pursue opportunities to augment our production and reserves, primarily targeting royalty interests, while maintaining a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future Unitholders.

DISTRIBUTION GUIDANCE

As a result of performance for the first nine months of 2004, we are lowering our annual production estimate by 65 boe per day to 5,600 boe per day. Nonetheless, given the current strength in commodity prices, we are increasing our estimate of cash distributions for 2004 to $1.73 per Trust Unit from our previous guidance of $1.67 per Trust Unit.

The regular monthly cash distribution is set at $0.12 per Trust Unit. In keeping with our stated practice, a portion of any excess income available for distribution may be directed toward repayment of long-term debt and/or working capital improvement where the board of directors consider it appropriate or necessary and extra distributions (quarterly top-ups) may be declared from time to time at the board's discretion.

Recognizing the cyclical nature of our industry, we continue to maintain a conservative outlook on commodity pricing. For 2005, we estimate distributions of $1.80 per Trust Unit, based on the following assumptions.

Distribution Outlook (as at November 10, 2004)	**2004**	**2005**
Estimated cash distributions ($ per Trust Unit)	**1.73**	**1.80**
Assumptions		
Average daily production, excluding acquisitions (boe/d)	**5,600**	**5,480**
Average WTI oil price (US$/bbl)	**42.00**	**40.00**
Average AECO natural gas price (C$/mcf)	**6.30**	**6.45**
Average light/heavy oil price differential (C$/bbl)	**14.00**	**14.00**
Average US/Cdn. dollar exchange rate	**0.77**	**0.80**
Capital expenditures ($ millions)	**5.1**	**5.0**

We caution that significant changes in production rates, commodity prices or foreign exchange rates (positive or negative) will result in adjustments to the distribution level. For example, if commodity prices weaken in 2005, and the Canadian dollar remains strong, revenues and distributions will be negatively affected. Freehold is particularly vulnerable to swings in the light/heavy oil differential price, as approximately 36% of our total boe production is heavy oil. An analysis of the potential impact of key variables on distributable income is provided on page 31 of the Trust's 2003 annual report to Unitholders.

The board of directors will evaluate the distribution outlook throughout the year and we will provide additional guidance as warranted.

As of the December 15, 2004 distribution payment, Freehold will have paid out a total of $10.16 per Trust Unit in distributions since inception, returning more than the $10.00 original investment of participants in the initial public offering in November 1996.

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COMBINED BALANCE SHEETS

($000s)	**September 30 2004**	December 31 2003
	(unaudited)	(restated–note 2)
Assets		
Current assets:		
Cash	**83**	57
Accounts receivable	**13,613**	11,629
	13,696	11,686
Reclamation fund	**1,556**	1,289
Petroleum and natural gas interests, net of accumulated depletion and depreciation of $174,397 (2003 – $155,258)	**186,869**	198,897
	202,121	211,872
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	**3,783**	3,145
Accounts payable and accrued liabilities	**4,691**	4,174
	8,474	7,319
Asset retirement obligation (notes 2 and 5)	**3,835**	3,606
Long-term debt (note 3)	**17,000**	18,000
Future income tax liability	**2,331**	1,955
Unitholders' equity (note 4)	**170,481**	180,992
	202,121	211,872

COMBINED STATEMENTS OF INCOME

(unaudited) ($000s, Except per Unit Data)	Three Months Ended September 30 **2004**	2003 (restated-note 2)	Nine Months Ended September 30 **2004**	2003 (restated-note 2)
Revenue:				
Royalty income and working interest sales	**20,726**	17,688	58,555	57,297
Royalty expense (net of ARC)	**(732)**	(823)	(2,245)	(2,558)
	19,994	16,865	56,310	54,739
Expenses:				
Operating	**1,530**	1,312	4,437	3,688
General and administrative	**731**	580	2,638	2,209
Interest on long-term debt	**145**	186	463	603
Depletion and depreciation	**6,367**	5,239	19,139	15,250
Accretion of asset retirement obligation	**59**	54	172	157
Management fee	**366**	308	1,035	867
	9,198	7,679	27,884	22,774
Net income before taxes	**10,796**	9,186	28,426	31,965
Income and capital taxes	**179**	73	555	238
Future income tax provision	**311**	245	376	596
Net income	**10,306**	8,868	27,495	31,131
Net income per Trust Unit, basic and diluted	**0.33**	0.28	0.87	1.00

COMBINED STATEMENTS OF UNITHOLDERS' EQUITY

(unaudited) ($000s)	**September 30 2004**	December 31 2003
Unitholders' equity, beginning of period, as previously reported	**181,093**	185,480
Retroactive adjustment for change in accounting policy (note 2)	**(101)**	(153)
As restated	**180,992**	185,327
Net income	**27,495**	37,078
Distributions to Unitholders	**(39,041)**	(53,149)
Issue of new Trust Units	**1,035**	11,736
Unitholders' equity, end of period	**170,481**	180,992

COMBINED STATEMENTS OF CASH FLOWS

(unaudited) ($000s)	Three Months Ended September 30 **2004**	2003 (restated-note 2)	Nine Months Ended September 30 **2004**	2003 (restated-note 2)
Cash provided by (used in):				
Operating:				
Net income	**10,306**	8,868	27,495	31,131
Items not involving cash:				
Depletion and depreciation	**6,367**	5,239	19,139	15,250
Future income tax provision	**311**	245	376	596
Accretion of asset retirement obligation	**59**	54	172	157
Trust Units issued in lieu of management fee	**366**	308	1,035	867
Funds generated from operations	**17,409**	14,714	48,217	48,001
Expenditures on site reclamation	**(17)**	(3)	(43)	(7)
Changes in non-cash working capital	**1,697**	912	(1,287)	1,456
	19,089	15,623	46,887	49,450
Financing:				
Trust Units issued upon exercise of options	**-**	1,201	-	10,501
Long-term debt	**-**	(1,000)	(1,000)	(12,500)
Distributions paid	**(14,176)**	(12,529)	(38,404)	(40,450)
	(14,176)	(12,328)	(39,404)	(42,449)
Investing:				
Corporate acquisition (note 7)	**(3,048)**	-	(3,048)	-
Property and royalty acquisitions	**116**	(292)	(214)	(1,814)
Development expenditures	**(2,278)**	(2,806)	(3,928)	(5,030)
Increase in site reclamation fund	**(86)**	(77)	(267)	(231)
	(5,296)	(3,175)	(7,457)	(7,075)
Increase (decrease) in cash	**(383)**	120	26	(74)
Cash, beginning of period	**466**	122	57	316
Cash, end of period	**83**	242	83	242

NOTES TO INTERIM COMBINED FINANCIAL STATEMENTS

For the period ended September 30, 2004 (unaudited)

1. SIGNIFICANT ACCOUNTING POLICIES

The interim combined financial statements of Freehold Royalty Trust "Freehold" have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim combined financial statements have been prepared following the same accounting policies and methods of computation as the combined financial statements for the fiscal year ended December 31, 2003, unless otherwise identified. The interim combined financial statements should be read in conjunction with the combined financial statements and the notes thereto in the Trust's annual report for the year ended December 31, 2003.

2. CHANGE IN ACCOUNTING POLICY

Asset Retirement Obligations

On January 1, 2004, Freehold adopted new Canadian accounting standards for asset retirement obligations. This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

Freehold now recognizes the fair value of an Asset Retirement Obligation (ARO) in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

Previously, Freehold recognized a provision for estimated future abandonment and site restoration costs calculated on the unit-of-production method over the remaining proved reserves. The annual charge was expensed as provision for future site restoration, with abandonment and site restoration expenditures charged to the accumulated provision as incurred.

This change in accounting policy resulted in the following increases (decreases) to Freehold's 2003 financial results:

($000s)	September 30, 2003 (three months)	September 30, 2003 (nine months)	December 31, 2003 (year)
Net income	5	(5)	52
Petroleum and natural gas interests, net of accumulated depletion and depreciation	1,775	1,775	1,732
Asset retirement obligation	3,563	3,563	3,606
Provision for future site restoration	(1,630)	(1,630)	(1,773)

The opening adjustment to 2004 Unitholders' equity was a reduction of $101,000 (2003 - $153,000). This reflects the cumulative impact of accretion and depletion expense, net of the previously recorded cumulative site restoration provision.

Petroleum and Natural Gas Interests

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties.

The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

Prior to January 1, 2004, the ceiling test amount was the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less estimated future costs for administration, financing and site restoration. The cash flows were estimated using period end prices and costs.

Freehold's calculation, performed at January 1, 2004, resulted in no impairment loss. The future prices Freehold used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for Freehold's quality, transportation, and contract differences.

3. LONG-TERM DEBT

Freehold has a $50.0 million committed production facility on which $17.0 million was drawn at September 30, 2004. The facility is structured as a one-year committed revolving credit facility, extendible annually. In the event that the lender does not consent to such extension, the revolving credit facility will revert to a three-year, non-revolving amortizing term loan with equal quarterly principal repayments. At September 30, 2004, the entire amount outstanding under the production facility is presented as long-term based on Freehold's ability to refinance this amount with the undrawn portion of the facility. Borrowings under the facility bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 90 to 165 basis points.

In addition, Freehold has available a $15.0 million demand operating facility and a U.S. $10.0 million swap facility which was unused at September 30, 2004. Borrowings under these facilities bear interest at the Bank's prime lending rate.

Cash interest paid during the nine months ended September 30, 2004 was $458,000 (2003 - $537,000) and for the current quarter was $147,000 (2003 - $181,000).

4. UNITHOLDERS' EQUITY

During the quarter, the Trust issued 22,500 Trust Units in payment for the management fee to Rife Resources Management Ltd. ("the Manager").

The total outstanding Trust Units at September 30, 2004 was 31,521,736 (2003 – 31,431,736). The weighted average number of Trust Units outstanding for the nine months ending September 30, 2004 was 31,477,064 (2003 – 31,073,906) and for the quarter was 31,499,481 (2003 – 31,335,024).

For the nine months ended September 30, 2004, the Manager charged the Trust $1,982,000 in general and administrative costs, of which $610,000 was for the current quarter. At September 30, 2004, there was $406,000 in accounts payable relating to these costs. As well, the Manager earns a fee of 1.5% of the purchase price of oil and gas properties acquired by Freehold, with the fee being $42,000 for the quarter and $47,000 for the nine months ended September 30, 2004.

5. ASSET RETIREMENT OBLIGATIONS

Freehold has no asset retirement obligations (ARO) on its royalty income properties. Freehold's ARO results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of Freehold's total ARO is estimated to be $3.8 million, with the undiscounted value being $9.6 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being over 15 years away. A credit adjusted risk free rate of 6.25% was used to calculate the present value of the ARO.

($000's)	September 30, 2004	December 31, 2003
Balance, beginning of period	$ 3,606	$ 3,289
Liabilities incurred	100	137
Liabilities settled	(43)	(34)
Accretion expense	172	214
Balance, end of period	$ 3,835	$ 3,606

6. COMPARATIVE FIGURES

Certain comparative figures have been restated to conform to the current year's financial statement presentation.

7. BUSINESS COMBINATION

On July 31, 2004 Freehold acquired all of the issued and outstanding shares of Ventana Ventures Inc., a private corporation, for cash. Ventana was the owner of producing royalty income properties in the Peace River area of Alberta. Results of operations for the acquisition have been included in Freehold's financial results for the period from August 1, 2004 onwards.

The transaction was accounted for by the purchase method with fair values as follows:

Net assets acquired	
Petroleum and natural gas interests	$2,868,000
Working capital	180,000
	$3,048,000

8. DISTRIBUTIONS TO UNITHOLDERS

(unaudited) ($000s, Except per Unit Data)	Three Months Ended September 30, **2004**	2003	Nine Months Ended September 30, 2004	2003
Funds generated from operations	**$ 17,409**	$ 14,714	$ 48,217	$ 48,001
Site reclamation fund contributions	**(103)**	(80)	(310)	(238)
Provision for capital expenditures	**(2,278)**	(2,200)	(3,928)	(5,000)
Debt additions (repayment from) cash flow	**-**	201	(1,000)	(1,999)
Corporate acquisition	**(3,048)**	-	(3,048)	-
Property and royalty acquisitions	**116**	(292)	(214)	(1,814)
Working capital change	**2,712**	202	(676)	1,624
Distributions to Unitholders	**$ 14,808**	$ 12,545	$ 39,041	$ 40,574
Per Trust Unit[1]	**$ 0.47**	$ 0.40	$ 1.24	$ 1.30

1 Based on the number of Trust Units issued and outstanding at each record date.