

NEWS RELEASE & QUARTERLY REPORT

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Freehold Royalty Trust Announces 2005 Third Quarter Results, 29% Increase in Monthly Distribution Rate, Plus a \$0.06 Extra Distribution

CALGARY, ALBERTA, (CCNMatthews – November 9, 2005) – Freehold Royalty Trust (Freehold or the Trust) (TSX:FRU.UN) today announced results for the period ended September 30, 2005.

THIRD QUARTER HIGHLIGHTS

- Production averaged 8,974 boe per day, up 65% from the third quarter of 2004.
- Price realizations averaged \$52.61 per boe, 28% higher than a year ago.
- Operating netback averaged \$49.89 per boe, up 35% from last year.
- Distributions to Unitholders totalled \$0.46 per Trust Unit (\$0.40 regular distribution plus \$0.06 top-up related to the second quarter of 2005).

The board of directors has declared an extra distribution of \$0.06 per Trust Unit (top-up related to excess funds from the third quarter). In addition, the regular monthly distribution has been increased 29% to \$0.18 per Trust Unit. The monthly distribution rate has increased 50% in 2005. The third quarter top-up will be paid on December 15, 2005, along with the regular monthly distribution (total of \$0.24 per Trust Unit.) The record date is November 30, 2005, and the ex-distribution date is November 28, 2005. Including the December 15 payment, the 12-month trailing cash distributions total \$1.78 per Trust Unit.

Results at a Glance	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
Financial (\$000s, except as noted)						
Gross revenue	43,936	20,726	112%	92,359	58,555	58%
Operating income						
Net income	19,373	10,306	88%	39,599	27,495	44%
Per Trust Unit, basic and diluted (\$)	0.40	0.33	21%	0.97	0.87	11%
Funds generated from operations ⁽¹⁾	38,893	17,392	124%	79,340	48,174	65%
Per Trust Unit (\$)	0.79	0.55	44%	1.95	1.53	27%
Distributions to Unitholders	22,527	14,808	52%	53,444	39,041	37%
Per Trust Unit ⁽²⁾ (\$)	0.46	0.47	-2%	1.28	1.24	3%
Long-term debt	118,000	17,000	594%	118,000	17,000	594%
Unitholders' equity	411,420	170,481	141%	411,420	170,481	141%
Operating						
Average daily production (boe/d)	8,974	5,447	65%	7,264	5,593	30%
Average price realizations (\$/boe)	52.61	40.96	28%	45.92	37.76	22%
Operating netback (\$/boe)	49.89	36.85	35%	43.03	33.85	27%
Trust Units Outstanding						
At period end	48,995,927	31,521,736	55%	48,995,927	31,521,736	55%
Weighted average	48,960,661	31,499,481	55%	40,728,537	31,477,064	29%

(1) Prior periods restated to conform to the current period's presentation.

(2) Based on the number of Trust Units issued and outstanding at each record date.

Message to Unitholders

The value of the Petrovera acquisition that we completed in May is clearly evident in our results. A 65% boost to oil and gas production and a 28% increase in average price realizations led to record revenue, funds generated from operations (cash flow), and net income in the third quarter of 2005. Operating costs and general and administrative expenses were lower on a per barrel of oil equivalent (boe) basis, reflecting the benefit of Petrovera royalty production for the full quarter.

The Petrovera properties contributed approximately 3,900 boe per day of royalty production for the quarter, and we are pleased with the drilling activity to date. Other royalty properties experienced modest production declines due to wet weather earlier this year. Our production remained unhedged, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our board of directors.

The board of directors has declared an extra distribution of \$0.06 related to the third quarter, and has raised the monthly distribution to \$0.18 per Trust Unit. This is our third distribution increase this year, and equates to a 50% increase from \$0.12 at the beginning of 2005. At the current monthly rate of \$0.18, our estimate of cash distributions for 2006 is \$2.16 per Trust Unit.

Federal Tax Consultation Process

On September 8, 2005, the Government of Canada's Department of Finance issued a consultation paper entitled *Tax and Other Issues Related to Publicly Listed Flow-Through Entities (Income Trusts and Limited Partnerships)*. The Government is concerned about what it sees as significant tax loss as a result of corporations converting to the income fund structure. It has also expressed concern that a slowdown of economic activity and reduced productivity could result when corporations convert to a structure that pays out a substantial portion of its cash flow in distributions. While consultations are underway and until the Government announces what action it will take, if any, it has declared a moratorium on advance tax rulings on these matters.

With a market value of approximately \$170 billion, income trusts comprise a significant portion of the public issuers in Canada, and trusts provide an important income stream for individuals, especially retirees and those planning retirement. The possibility that the Government may impose additional taxes or restrictions on income trusts has created considerable uncertainty in the market. It is of paramount importance for the success of any business and economy that tax rules be consistent and transparent.

Since its formation in November 1996 to September 30, 2005, Freehold Royalty Trust has provided Unitholders with an 87% capital appreciation in the unit price, and cash distributions of \$351.7 million, or \$11.56 per unit. Funds from operations are used to appropriately sustain and grow the business and the remaining free cash flow is distributed to investors who either currently pay or ultimately will pay tax – at a generally higher personal rate than do corporations.

We encourage our Unitholders to participate in the Government's consultation process. More information on the process can be found on the Department of Finance website, at: http://www.fin.gc.ca/activty/consult/flwthruent_e.html. Unitholders may also express their views directly to the Minister of Finance, whose contact information is available at <http://www.fin.gc.ca/admin/contact-e.html>.

On behalf of the Board of Directors
of Freehold Resources Ltd.,



David J. Sandmeyer
President & Chief Executive Officer

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 and nine months ended September 30, 2005 and previous periods, and the outlook for Freehold based on information available as at November 9, 2005. 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, 2005 and September 30, 2004, 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 financial statements for the years ended December 31, 2004 and 2003, together with the accompanying notes. These are included on pages 19 through 44 of the Trust's 2004 annual report to Unitholders.

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at November 9, 2005, 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. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them.

CRITICAL ACCOUNTING ESTIMATES

The assets, liabilities, revenues and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, and oil and gas revenue accruals. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

We continually evaluate the estimates and assumptions. In the normal course, changes are made to assumptions underlying all critical accounting estimates to reflect current economic conditions and updating of historical information used to develop the assumptions. Except as discussed in this Management's Discussion and Analysis, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

Freehold follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. We expect that these accrual estimates will be revised, upwards or downwards, based on the receipt of actual results.

The Trust has no operational control over its royalty lands, and it primarily holds small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult. As a result, we use government reporting databases and past production receipts to estimate revenue accruals. The increase in royalty interest production with the Petrovera acquisition in May required a corresponding increase in our revenue accruals. The increase is reflected in higher accounts receivables.

SUPPLEMENTAL DISCLOSURE

We believe that distributions to Unitholders, cash flow and netback are useful supplemental measures. You are cautioned that distributions to Unitholders should not be construed as an alternative to net income as determined by GAAP. Cash flow, as used in this report, refers to funds generated from operations derived from our Consolidated 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 measures 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

The table below is a summary of our performance for the third quarter of 2005, with comparative data for the preceding seven quarters. This presentation illustrates the fluctuations in pricing experienced over the past eight quarters, and the resultant effect on our financial results. In recent quarters, our results have benefited from strong commodity prices.

On May 10, 2005, we acquired Petrovera Resources, a general partnership, for \$351.7 million, net of adjustments. The purchase price was funded with a combination of equity and debt. The acquisition was accounted for using the purchase method of accounting, with results of operations included from May 10, 2005. The purchase price equation has not been finalized and is subject to certain revenue adjustments at the end of the first quarter of 2006. The Petrovera acquisition resulted in a step change in our production volumes.

Quarterly Results (\$000s, except as noted)	2005			2004			2003	
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Financial								
Revenue, net of royalty expense	42,867	27,922	19,170	19,204	19,994	19,066	17,250	15,230
Funds generated from operations ⁽¹⁾	38,893	24,344	16,103	16,139	17,392	16,407	14,375	12,664
Per Trust Unit (\$)	0.79	0.59	0.51	0.51	0.55	0.52	0.46	0.40
Distributions to Unitholders	22,527	17,981	12,936	15,449	14,808	12,593	11,640	12,575
Per Trust Unit (\$)	0.46	0.41	0.41	0.49	0.47	0.40	0.37	0.40
Payout ratio (%)	58	74	80	96	85	77	81	99
Net income ⁽²⁾	19,373	10,858	9,368	9,397	10,306	9,515	7,674	5,947
Per Trust Unit, basic and diluted (\$)	0.40	0.26	0.30	0.30	0.33	0.30	0.24	0.19
Long-term debt	118,000	120,000	27,000	27,000	17,000	17,000	18,000	18,000
Operating								
Daily production (boe/d)	8,974	7,279	5,502	5,575	5,447	5,757	5,577	5,768
Average selling price (\$/boe)	52.61	42.42	39.47	38.37	40.96	37.37	35.00	29.51
Operating netback (\$/boe)	49.89	39.61	36.18	34.67	36.85	33.57	31.18	25.88
Benchmark Prices								
WTI crude oil (US\$/bbl)	63.19	53.20	49.84	48.28	43.88	38.31	35.14	31.18
Exchange rate (Cdn\$/US\$)	0.8325	0.8039	0.8150	0.8195	0.7651	0.7357	0.7590	0.7600
Edmonton Par (Cdn\$)	76.51	65.76	61.45	57.70	56.25	50.60	45.60	39.55
Light/heavy oil differential (Cdn\$/bbl)	20.79	24.17	22.48	21.60	14.29	13.29	10.67	11.02
Bow River/Hardisty (Cdn\$/bbl)	55.72	41.59	38.97	36.10	41.96	37.31	34.93	28.53
AECO natural gas (Cdn\$/Mcf)	8.17	7.38	6.69	7.08	6.66	6.80	6.61	5.59
Unit Trading Performance								
High (\$)	19.30	17.63	18.49	18.42	16.97	15.80	16.30	17.19
Low (\$)	15.99	14.25	15.50	15.75	14.57	14.65	14.02	13.11
Close (\$)	18.68	15.99	16.10	17.45	16.25	15.00	14.75	16.35
Volume (000s)	9,980	8,311	2,418	4,252	1,768	3,149	2,399	2,506

(1) Prior periods restated to conform to the current period's presentation.

(2) 2003 restated.

(3) Based on the number of Trust Units issued and outstanding at each record date.

NET INCOME AND FUNDS GENERATED FROM OPERATIONS

Additional royalty production from the Petrovera acquisition and higher average selling prices led to record income and funds generated from operations (cash flow) for the third quarter of 2005.

Net Income and Funds Generated From Operations	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
Net income (\$000s)	19,373	10,306	88%	39,599	27,495	44%
Per Trust Unit, basic and diluted (\$)	0.40	0.33	20%	0.97	0.87	11%
Funds generated from operations (\$000s)	38,893	17,392	124%	79,340	48,174	65%
Per Trust Unit (\$)	0.79	0.55	44%	1.95	1.53	27%

DISTRIBUTIONS TO UNITHOLDERS

Distributions to Unitholders for the third quarter of 2005 were \$22.5 million, or \$0.46 per Trust Unit, compared with \$14.8 million, or \$0.47 per Trust Unit, in the third quarter last year. Royalty income contributed 93% of distributions, up from 83% in the third quarter last year. The board of directors has declared an extra distribution of \$0.06 per Trust Unit related to excess funds from the third quarter, which will be paid in December. In addition, the regular monthly distribution increases 29% to \$0.18 per Trust Unit beginning with the December 15 payment. The monthly distribution has increased 50% in 2005 from \$0.12 per month at the beginning of the year.

Distributions to Unitholders (\$000s, except as noted)	Three Months Ended		Nine Months Ended	
	September 30		September 30	
	2,005	2,004	2,005	2,004
Funds generated from operations	38,893	17,392	79,340	48,174
Net reclamation fund contribution	(105)	(86)	(246)	(267)
Capital expenditures	(4,059)	(2,278)	(6,351)	(3,928)
Debt additions (repayment)	(2,000)	—	91,000	(1,000)
Proceeds from Trust Unit issuance	—	—	258,935	—
Corporate acquisition	—	(3,048)	—	(3,048)
Property and royalty acquisitions	—	116	(351,705)	(214)
Changes in working capital	(10,202)	2,712	(17,529)	(676)
Distributions to Unitholders	22,527	14,808	53,444	39,041
Accumulated, beginning of period	329,131	267,957	298,214	243,724
Accumulated, end of period	351,658	282,765	351,658	282,765
Distributions per Trust Unit⁽¹⁾ (\$)	0.46	0.47	1.28	1.24
Accumulated, beginning of period	11.10	9.32	10.28	8.55
Accumulated, end of period	11.56	9.79	11.56	9.79

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

The payout ratio for the third quarter, which excludes the \$0.06 quarterly top-up, was 58%. The lower payout ratio (58% versus 85% in 2004) indirectly reflects the step change in our production volumes with the Petrovera acquisition. The increase in royalty interest production and higher product prices required a corresponding increase in our accounts receivables, caused by the normal lag in receiving royalty revenue. The increase in accounts receivable is included in changes in working capital. In 2006, our payout ratio is expected to be approximately 80%.

Payout Ratio ⁽¹⁾ (\$/Trust Unit, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
Funds generated from operations	0.79	0.55	44%	1.95	1.53	27%
Distributions to Unitholders	0.46	0.47	-2%	1.28	1.24	3%
Payout ratio	58%	85%	-32%	66%	81%	-19%

(1) Distributions to Unitholders as a percentage of funds generated from operations.

Upcoming Distributions			
Record Date	Ex-Distribution Date	Payment Date	Distribution Amount (\$/Trust Unit)
October 31, 2005	October 27, 2005	November 15, 2005	0.14
November 30, 2005	November 28, 2005	December 15, 2005	0.24 ⁽¹⁾
December 31, 2005	December 28, 2005	January 15, 2006	0.18 ⁽²⁾
January 31, 2006	January 27, 2006	February 15, 2006	0.18 ⁽²⁾

(1) Payment includes \$0.06 quarterly top-up related to excess funds from the third quarter.

(2) Estimated distribution is based on current market outlook and subject to change.

NETBACK

Our third quarter operating netback was \$49.89 per boe, 35% higher than last year, reflecting higher commodity prices in 2005. Year-to-date, the operating netback averaged \$43.03, up 27%. We do not have any commodity price or foreign currency hedges in place. Because we do not incur royalty expenses or operating expenses on our royalty lands, we have consistently delivered a superior netback relative to our peer group.

Operating Netback (\$/boe)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
Gross revenue ⁽¹⁾	53.22	41.36	29%	46.57	38.21	22%
Royalty expenses ⁽²⁾	1.30	1.46	-11%	1.21	1.46	-17%
Operating expenses	2.03	3.05	-33%	2.33	2.90	-20%
Operating netback	49.89	36.85	35%	43.03	33.85	27%

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

(2) Net of Alberta Royalty Tax Credit.

PRODUCTION

Average daily production volumes rose 65% in the third quarter and 30% for the nine months ended September 30, 2005. The Petrovera acquisition contributed approximately 3,900 boe per day of royalty production for the quarter, causing both natural gas production and royalty production volumes to double. Other royalty properties experienced production declines largely due to an early spring break-up and wet weather in the second quarter which curtailed access and delayed the tie-in of new wells. Working interest production was slightly lower than last year for the same reason. Our production profile year to date for 2005 was 36% natural gas, 4% natural gas liquids (NGL), 22% light and medium oil, and 38% heavy oil (on a boe basis).

Freehold's December 2005 production rate is expected to be approximately 9,200 boe per day, reflecting additions to production from the strong drilling during the third quarter of 2005.

Average Daily Production	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
Royalty lands						
Oil (bbls/d)	3,756	2,199	71%	3,011	2,183	38%
NGL (bbls/d)	310	208	49%	277	214	29%
Natural gas (Mcf/d)	18,860	7,501	151%	13,292	7,953	67%
Oil equivalent (boe/d)	7,211	3,657	97%	5,504	3,722	48%
Working interest properties						
Oil (bbls/d)	1,260	1,275	-1%	1,308	1,382	-5%
NGL (bbls/d)	61	66	-8%	59	64	-8%
Natural gas (Mcf/d)	2,653	2,690	-1%	2,360	2,549	-7%
Oil equivalent (boe/d)	1,763	1,789	-1%	1,760	1,871	-6%
Total Trust						
Oil (bbls/d)	5,016	3,474	44%	4,319	3,565	21%
NGL (bbls/d)	371	274	35%	336	278	21%
Natural gas (Mcf/d)	21,513	10,191	111%	15,652	10,502	49%
Oil equivalent (boe/d)	8,974	5,447	65%	7,264	5,593	30%
Number of days in period (days)	92	92	0%	273	274	0%
Total volumes during period (Mboe)	826	501	65%	1,983	1,533	29%
Potash production (tonnes/d)	8.6	5.2	65%	9.3	7.3	27%

BENCHMARK PRICES

Hurricanes Katrina and Rita devastated the Gulf Coast region in the third quarter, causing massive property destruction and human misery, as well as damage to oil platforms, refineries, and natural gas production facilities. The storms knocked out about one-quarter of U.S. output and 28% of U.S. refining capacity, severely curtailing oil and natural gas production and refining throughout the region for several weeks. In such tight markets, the temporary loss of supply sent energy prices soaring to all-time highs.

WTI crude oil prices rose 44%, while Edmonton Par prices rose 36%, reflecting a stronger Canadian dollar. But despite its recent surge, the average price of crude oil, adjusted for inflation, is still below the peak price in the early 1980s, which was just over US\$90 a barrel in today's dollars. The lack of refining capacity has amplified the disparity between the demand for light oil and the world's supply of heavier and more sour crude production. This mismatch is reflected in the significant price differential between light and heavy oil. Several of the Gulf Coast refineries damaged by hurricanes were heavy oil refineries, which may put additional pressure on heavy oil prices. AECO natural gas prices were up 23% in the quarter and up 11% for the year to date.

Average Benchmark Prices	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
WTI crude oil (US\$/bbl)	63.19	43.88	44%	55.40	39.11	42%
US\$/Cdn\$ exchange rate	0.8325	0.7651	9%	0.8172	0.7533	8%
Edmonton Par crude oil (Cdn\$/bbl)	76.51	56.25	36%	67.91	50.82	34%
Light/heavy oil differential (Cdn\$/bbl)	20.79	14.29	45%	22.48	12.75	76%
Bow River/Hardisty (Cdn\$/bbl)	55.72	41.96	33%	45.42	38.07	19%
AECO natural gas (Cdn\$/Mcf)	8.17	6.66	23%	7.41	6.69	11%

The fundamental outlook for oil and gas producers is positive for 2006 and through the remainder of the decade. The global oil market remains tight and geopolitical issues in the Middle East, Nigeria, and Venezuela continue to create uncertainty in world markets. In North America, demand for natural gas continues to outpace supply. The impact of hurricanes will further strain supply, heading into the winter heating season. A colder than normal winter could push gas prices even higher, as supply remains a concern with Canadian conventional production declining.

FREEHOLD'S REALIZED PRICES

Our average price realizations were 28% higher than the third quarter of 2004 and 22% higher than the first nine months of last year. Realized selling prices in Canadian dollars are affected by currency exchange rates, as oil and natural gas prices are denominated in U.S. dollars. Freehold's realized prices also reflect quality and transportation differences. The differential is significant for Freehold, as approximately 60% of our oil production (40% of our total boe production) is heavy oil. The cost of purchased condensate, used as a diluent and blending agent for transport of heavy oil, has also risen dramatically in 2005.

Average Selling Prices	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
Oil (\$/bbl)	56.46	43.19	31%	46.99	38.08	23%
NGL (\$/bbl)	54.21	40.08	35%	47.60	36.09	32%
Oil and NGL (\$/bbl)	56.31	42.97	31%	47.03	37.94	24%
Natural gas (\$/Mcf)	7.84	6.09	29%	7.32	6.23	17%
Oil equivalent (\$/boe)	52.61	40.96	28%	45.92	37.76	22%
Potash (\$/tonne)	234.72	174.14	35%	216.31	161.37	34%

DEVELOPMENT ACTIVITIES

In the second half of 2005, the oil and gas industry resumed its record-setting pace and is on track to drill a record number of wells again this year. More than 5,900 wells were drilled in western Canada during the third quarter, as the industry sought to make up for lost time earlier this year as a result of an early spring break-up, extended road bans, and record rainfall and flooding on the southern Prairies. In the current pricing environment, industry activity levels are anticipated to remain robust. The Petroleum Services Association of Canada predicts that more than 25,000 wells will be drilled in western Canada in 2006.

ROYALTY INTEREST LANDS

Drilling activity on Freehold's royalty lands was robust in the third quarter. A total of 250 wells were drilled on our royalty lands, including 101 (0.2 net) unit wells in which we have very small royalty interests. On an equivalent net basis, this is 8.3 net wells, up from 5.0 net wells in the third quarter of 2004. These wells were drilled at no cost to Freehold.

Drilling on the Petrovera lands continued with 71 gross (3.5 equivalent net) wells. The targets were mostly for oil. Licensed locations totalled 54 (2.0 net) at the end of September 2005.

Combined, there are currently 99 (3.9 equivalent net) licensed drilling locations on our royalty lands, compared with 60 (2.0 equivalent net) locations at this time last year, signalling a very strong fourth quarter for royalty drilling.

Royalty Interest Lands Drilling Summary ⁽¹⁾	Three Months Ended September 30				Nine Months Ended September 30			
	2005		2004		2005		2004	
	Gross	Net ⁽²⁾	Gross	Net ⁽²⁾	Gross	Net ⁽²⁾	Gross	Net ⁽²⁾
Oil	55	2.8	49	2.2	140	5.5	120	3.4
Natural gas	125	2.0	44	2.2	420	4.6	349	3.8
No status, service and other	69	3.5	16	0.4	153	8.3	52	2.0
Dry and abandoned	1	—	3	0.2	2	0.1	4	0.2
Total	250	8.3	112	5.0	715	18.5	525	9.4

(1) Includes drilling on the Petrovera lands from January 1, 2005 (the effective date of the acquisition), but excludes any wells drilled in Ontario. Gross wells adjusted for wells with both an original Freehold and acquired Petrovera interest.

(2) Equivalent net wells are the aggregate of the numbers obtained by multiplying each gross well by the Trust's royalty interest percentage.

Summary of Royalty Wells Drilled	Nine Months Ended September 30, 2005		
	Original Freehold	Petrovera	Combined ⁽¹⁾
Gross wells	590	236	715
Equivalent net wells ⁽²⁾	10.3	8.2	18.5
Net success rate (%)	99.8	98.7	99.7

- (1) Combined gross wells adjusted for wells with both original Freehold and acquired Petrovera interests.
(2) Equivalent net wells are the aggregate of the numbers obtained by multiplying each gross well by the Trust's royalty interest percentage.

WORKING INTEREST PROPERTIES

In the third quarter of 2005, we spent \$4.1 million on facilities and the drilling of 62 (6.1 net) wells. This activity resulted in 23 oil wells, 37 natural gas wells, and 2 unclassified wells, for a 100% success rate.

At Hayter, September was the first full month of production from our 2005 development program. All of the 11 (2.6 net) wells planned for 2005 have been drilled, tied in and are on production. In October, approximately 700 boe/d of production at Hayter was shut-in for two weeks (approximately 25 boe/d annualized) while we completed an annual turnaround (plant maintenance). The turnaround was originally scheduled for May but was postponed due to wet weather.

At Pembina Cardium Unit #9, the operator drilled 7 (0.7 net) wells in the third quarter. The remaining 11 (1.1 net) wells in the 20-well program are being deferred until 2006. Three (0.7 net) wells were drilled at Pouce-Coupe, 2 (1.5 net) wells were drilled at Lashburn, 34 (0.5 net) gas wells, were drilled at Brownfield and 1 (0.5 net) gas well was drilled at Willesden Green.

Working Interest Properties Drilling Summary	Three Months Ended September 30				Nine Months Ended September 30			
	2005		2004		2005		2004	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	23	4.9	13	3.0	33	5.7	23	3.3
Natural gas	37	1.0	2	0.0	58	1.2	26	0.5
Other	2	0.2	—	—	2	0.2	—	—
Total	62	6.1	15	3	93	7.1	49	3.8

Development expenditures are expected to be approximately \$2.0 million in the fourth quarter. Drilling will continue at Willesden Green with 1 (0.25 net) well. Two (0.6 net) wells are planned at Queensdale, and 1 (0.3 net) well is planned at Wordsworth. Expenditures on facilities to tie-in the wells drilled during the third quarter will also occur in the fourth quarter.

REVENUE

We receive revenue from about 200 industry operators. Gross revenue more than doubled in the third quarter, to \$43.9 million from \$20.7 million in the same period last year. Approximately 72% of the increase is attributed to higher production volumes as a result of the Petrovera acquisition, with the remainder due to higher commodity prices. Year-to-date, increased production volumes accounted for 61% of the revenue increase, with higher commodity prices accounting for 39% of the increase.

The accompanying table demonstrates the net effect of price and volume variances on gross revenues. "Other" includes Potash revenue, sulphur revenue, lease rentals, processing fees and interest income.

Gross Revenue Variances (\$000s)	Three Months Ended September 30		Nine Months Ended September 30	
	2005 vs. 2004	2004 vs. 2003	2005 vs. 2004	2004 vs. 2003
	Oil and NGL			
Production increase (decrease)	8,494	(1,460)	10,257	(1,438)
Price increase (decrease)	4,601	4,468	9,576	4,323
Net increase (decrease)	13,095	3,008	19,833	2,885
Natural gas				
Production increase (decrease)	8,168	(310)	10,221	(832)
Price increase (decrease)	1,642	352	3,154	(733)
Net increase (decrease)	9,810	42	13,375	(1,565)
Other	305	(12)	596	(62)
Gross revenue increase (decrease)	23,210	3,038	33,804	1,258

EXPENSES

ROYALTIES PAID

Royalty expenses are tied directly to commodity prices and working interest production volumes. In the third quarter, royalty expenses per boe declined 11%, reflecting the increase in royalty production volumes, which have no royalty expenses. We paid royalty expenses of \$6.59 per boe relating to ownership in working interest production.

Royalty Expenses (net of Alberta Royalty Credit)	Three Months Ended September 30			Nine Months Ended September 30		
	2005	2004	Change	2005	2004	Change
	Working interest properties (\$000s)	1,069	732	46%	2,400	2,245
Per boe (\$)	6.59	4.44	48%	5.00	4.38	14%
Royalty interest lands ⁽¹⁾ (\$000s)	0	0	—	0	0	—
Per boe (\$)	0	0	—	0	0	—
Total royalty expenses (\$000s)	1,069	732	46%	2,400	2,245	7%
Total Trust (\$/boe)	1.30	1.46	-11%	1.21	1.46	-17%

(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

With the benefit of Petrovera royalty production for the full period, operating costs for the third quarter were \$2.03 per boe, 33% lower than last year. Approximately 80% of our production comes from royalty interests, on which we pay no operating costs. Operating expenses on our working interest properties were \$10.35 per boe for the third quarter, up 11% from 2004. Record activity levels have created high demand for oilfield services, which has caused inflationary pressures as high as 25 percent throughout the oil and gas sector. The industry is experiencing rising operating costs, higher finding and development costs, and a shortage of experienced professionals and tradespeople. Our focus on royalty interests provides some shelter from these inflationary effects, because the operators pay royalties to us based on gross production revenue, before deduction of operating expenses.

Operating Expenses	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
Working interest properties (\$000s)	1,679	1,530	10%	4,618	4,437	4%
Per boe (\$)	10.35	9.29	11%	9.61	8.65	11%
Royalty interest lands ⁽¹⁾ (\$000s)	0	0	—	0	0	—
Per boe (\$)	0	0	—	0	0	—
Total operating expenses (\$000s)	1,679	1,530	10%	4,618	4,437	4%
Total Trust (\$/boe)	2.03	3.05	-33%	2.33	2.90	-20%

(1) We do not incur operating expenses on production from our royalty lands.

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

G&A expenses for the third quarter of 2005 rose 32%, reflecting an increase in the Manager's staff levels compared with the third quarter last year, and rising costs associated with regulatory compliance and financial reporting. On a per boe basis, G&A expenses declined 20% compared with last year, as production volumes increased. Synergies and economies of scale resulting from the Petrovera acquisition are expected to further reduce G&A expenses on a per boe basis, once the integration is complete.

For the nine months ended September 30, 2005, the Manager charged the Trust \$2.2 million in G&A costs. At September 30, 2005, there was \$0.5 million in accounts payable relating to these costs.

G&A Expenses	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
G&A expenses (\$000s)	964	731	32%	3,170	2,638	20%
Per boe (\$)	1.17	1.46	-20%	1.60	1.72	-7%
As a percentage of revenue	2.2%	3.5%	-37%	3.4%	4.5%	-24%

MANAGEMENT FEES

The Manager of the Trust receives its management fee in Trust Units. The issue of 17.4 million Trust Units in May resulted in a pro-rata increase in the management fee, in accordance with the management contract. The management fee for the third quarter of 2005 was 35,654 Trust Units (2004 – 22,500 Trust Units). The ascribed value of the management fee was \$0.7 million (\$0.81 per boe), based on the closing price of the Trust Units on September 30, 2005. The Manager also earns a fee of 1.5% of the purchase price of oil and gas properties acquired by the Trust. In connection with the Petrovera acquisition, an acquisition fee of \$5.3 million was paid to the Manager, in accordance with the management contract.

Management Fees (\$000s, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
Management fees (paid in Trust Units) ⁽¹⁾	666	366	82%	1,508	1,035	46%
Per boe (\$)	0.81	0.73	11%	0.76	0.68	12%
Acquisition fees ⁽²⁾	0	42		5,306	47	

(1) The ascribed value of the management fees is based on the closing Trust Unit price at the end of each quarter.

(2) The Manager earns an acquisition fee of 1.5% of the purchase price of oil and gas properties that we acquire. This fee is charged to capital assets as part of the properties acquired.

INTEREST EXPENSES

Additional debt assumed in May to finance the Petrovera acquisition resulted in increased interest expense. In the third quarter, interest expenses totalled \$1.1 million, or \$1.31 per boe.

Interest Expenses (\$000s, except as noted)	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
Net interest expense	1,082	145	646%	2,017	463	336%
Per boe (\$)	1.31	0.29	352%	1.02	0.30	239%

LIQUIDITY AND CAPITAL RESOURCES

In conjunction with the Petrovera acquisition, we expanded our credit facilities from \$65 million to \$165 million. These credit facilities were used to fund \$93 million of the purchase price for the acquisition, inclusive of transaction costs.

At the end of the third quarter, we had no short-term debt outstanding and long-term debt was \$118 million. We had working capital of \$21.7 million, resulting in net debt of \$96.3 million. The Trust's ratio of net debt (long-term debt less positive working capital) to trailing cash flow was 1:1.

Debt Analysis (\$000s)	As at September 30		
	2005	2004	Change
Long-term debt	118,000	17,000	594%
Short-term debt	0	0	—
Less: working capital	(21,656)	(5,222)	315%
Net debt obligations	96,344	11,778	718%

Financial Leverage and Coverage Ratios ⁽¹⁾	As at September 30		
	2005	2004	Change
Net debt to cash flow (times)	1.0	0.2	421%
Net debt to distributions (times)	1.4	0.2	513%
Distributions to interest expense (times)	31.5	80.8	-61%
Net debt to net debt plus equity (%)	19	6	193%

(1) Cash flow, distributions and interest expense are 12-months trailing.

The increased royalty interest production from the Petrovera acquisition has required a significant, one-time increase in our receivables, caused by the normal lag in receiving royalty revenue. The dollar amount of receivables also increased due to higher commodity prices. These increases resulted in a change to working capital of \$10.2 million (\$0.20 per Trust Unit during the third quarter and \$23 million (\$0.50 per Trust Unit) for the year to date.

We are taking what steps we can to speed up receipt of royalty income. For example, some of our leases allow for us to take our oil production in-kind. By year end, we will be taking in-kind approximately 40 per cent of our royalty oil production. As a result, we will be receiving this revenue roughly one month quicker than would otherwise be the case.

Components of Working Capital (\$000s)	September 30 2005	June 30 2005	March 31 2005	December 31 2004
Cash	17	215	146	66
Accounts receivable	35,211	21,707	13,642	12,797
Current assets	35,228	21,922	13,788	12,863
Distributions payable to Unitholders	6,859	5,875	3,788	3,785
Accounts payable and accrued liabilities	6,713	4,593	3,829	4,950
Current liabilities	13,572	10,468	7,617	8,735
Working capital ⁽¹⁾	21,656	11,454	6,171	4,128

(1) Working capital is comprised of current assets minus current liabilities.

CAPITAL EXPENDITURES

Capital expenditure obligations are deducted from funds generated from operations before determining distributions to Unitholders. As we do not incur any capital expenditures on our royalty properties, our capital requirements are modest, relative to most energy trusts. Capital expenditures on working interest properties totalled \$4.1 million in the third quarter (2004 – \$2.3 million) and \$6.4 million for the first nine months of 2005 (2004 – \$3.9 million).

As a result of increased development activity, we are raising our estimate of capital expenditures for 2005 to \$8.4 million (previously \$6.6 million). Development expenditures in the last three months of 2005 will be approximately \$2 million, funded from cash flow.

TRUST UNITS OUTSTANDING

In connection with the Petrovera acquisition, we issued 17,363,520 Trust Units at \$15.55 per Trust Unit on May 10, 2005. On September 30, 2005, we issued 35,654 Trust Units in payment of the management fee. As at September 30, 2005 and November 9, 2005, there were 48,995,927 Trust Units outstanding. There are no options outstanding under the Trust Unit option plan.

Trust Units Outstanding	Three Months Ended			Nine Months Ended		
	September 30			September 30		
	2005	2004	Change	2005	2004	Change
At period end	48,995,927	31,521,736	55%	48,995,927	31,521,736	55%
Weighted average	48,960,661	31,499,481	55%	40,728,537	31,477,064	29%

OTHER DEVELOPMENTS

INDEX INCLUSION

Freehold has been informed that it will be included as one of the income trusts in the new S&P/TSX Composite Index scheduled to be implemented in December 2005.

FOREIGN OWNERSHIP UPDATE

Our Trust Indenture provides that not more than 49 per cent of the Trust's Units can be held by non-residents. We monitor foreign ownership levels on a regular basis through declarations from Unitholders and geographical searches. Based on geographical data as of July 27, 2005, we estimate that approximately 78% of the Trust's Units are held by Canadian residents, with the remaining 22% held by non-residents. While the Trust believes that these results are reasonable estimations at the time that they are provided, the inability of all public issuers to obtain the residency information of their beneficial holders means that issuers must rely upon the information provided to the transfer agent. As a result, the residency information is subject to the accuracy provided by third party data and by system limitations. Accordingly, the reported level of Canadian ownership is subject to these limitations and the level of Canadian ownership may change at any time without notice.

FEDERAL TAX CONSULTATION PROCESS

On September 8, 2005, the Government of Canada's Department of Finance issued a consultation paper entitled *Tax and Other Issues Related to Publicly Listed Flow-Through Entities (Income Trusts and Limited Partnerships)*. The deadline for submissions is December 31, 2005. While the consultations are underway and until the Government announces what action it will take, if any, it has declared a moratorium on advance tax rulings on these matters. The announcement has created significant uncertainty in the income trust market.

DISTRIBUTION OUTLOOK

The regular monthly distribution has been increased to \$0.18 per Trust Unit, effective with the December 15 payment. The continued strength in commodity pricing leads us to increase our estimate of cash distributions for 2005 to \$1.84 per Trust Unit, up from our earlier guidance of \$1.80. As a result of performance for the first nine months, our 2005 average production is now forecast to be 7,725 boe per day, with an exit rate of 9,200 boe per day. This is 170 boe per day lower than our previous guidance, but 38% higher than our average production in 2004.

For 2006, we estimate distributions of \$2.16 per Trust Unit, based on monthly distributions of \$0.18 per Trust Unit. This estimate does not assume quarterly top-ups. At the board's discretion, any excess income available for distribution will be directed toward repayment of long-term debt and improvements to working capital, and extra distributions may be declared from time to time. Other key assumptions are provided in the table below.

Recognizing the cyclical nature of our industry, we caution that significant changes in production rates, commodity prices, interest rates or foreign exchange rates (positive or negative) will result in adjustments to the distribution level. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as approximately 40% of our total boe production is heavy oil. An analysis of the potential impact of key variables on distributions to Unitholders is provided on page 34 of the Trust's 2004 annual report to Unitholders.

Distribution Outlook (as at November 9, 2005)	2005	2006
Estimated cash distributions (\$ per Trust Unit)	1.84	2.16
Assumptions		
Average daily production (boe/d)	7,725	8,600
Average WTI oil price (US\$/bbl)	56.75	60.00
Average AECO natural gas price (Cdn\$/Mcf)	8.15	10.00
Average light/heavy oil price differential (Cdn\$/bbl)	24.00	28.00
Average exchange rate (Cdn\$/US\$)	0.82	0.85
Capital expenditures (\$ millions)	8.4	6.0
Long-term debt at year end (\$ millions)	113	91
Weighted average Trust Units outstanding (thousands)	42,812	49,086
Payout ratio (%)	69	80
Estimated taxability of distributions, as other income (%)	80	85

TAXABILITY OF DISTRIBUTIONS

For Canadian tax purposes, we estimate that approximately 80% of the distributions pertaining to 2005 will be taxable as other income, and 20% will be a tax-deferred return of capital. The actual taxability of 2005 distributions will be determined and reported to Unitholders prior to the end of the first quarter of 2006.

Based on there being no changes regarding the taxation of income trusts, for 2006 we estimate that approximately 85% distributions will be taxable.

FOR FURTHER INFORMATION, PLEASE CONTACT:

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Karen Taylor, Manager, Investor Relations (403) 221-0891

Freehold Royalty Trust

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Consolidated Balance Sheets

(\$000s)	September 30, 2005 (unaudited)	December 31, 2004
Assets		
Current assets:		
Cash	\$ 17	\$ 66
Accounts receivable	35,211	12,797
	35,228	12,863
Reclamation fund	1,892	1,646
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$219,037 (2004 – \$180,919)	513,604	193,492
	\$ 550,724	\$ 208,001
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	\$ 6,859	\$ 3,785
Accounts payable and accrued liabilities	6,713	4,950
	13,572	8,735
Asset retirement obligation (note 5)	4,225	3,937
Long-term debt (note 3)	118,000	27,000
Future income tax liability	3,507	3,507
Unitholders' equity:		
Unitholders' capital (note 4)	559,379	298,936
Accumulated earnings	203,699	164,100
Accumulated distributions	(351,658)	(298,214)
	411,420	164,822
	\$ 550,724	\$ 208,001

Consolidated Statements of Income and Accumulated Earnings

(unaudited) (\$000s, Except per Unit Data and Weighted Average Data)	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Revenue:				
Royalty income and working interest sales	\$ 43,936	\$ 20,726	\$ 92,359	\$ 58,555
Royalty expense (net of Alberta Royalty Tax Credit)	(1,069)	(732)	(2,400)	(2,245)
	42,867	19,994	89,959	56,310
Expenses:				
Operating	1,679	1,530	4,618	4,437
General and administrative	964	731	3,170	2,638
Interest on long-term debt	1,082	145	2,017	463
Depletion and depreciation	18,792	6,367	38,118	19,139
Accretion of asset retirement obligation	63	59	185	172
Management fee	666	366	1,508	1,035
	23,246	9,198	49,616	27,884
Net income before taxes	19,621	10,796	40,343	28,426
Income and capital taxes	248	179	744	555
Future income tax provision	-	311	-	376
	248	490	744	931
Net income	19,373	10,306	39,599	27,495
Accumulated earnings – beginning of period	184,326	144,397	164,100	127,208
Accumulated earnings – end of period	\$ 203,699	\$ 154,703	\$ 203,699	\$ 154,703
Net income per Trust Unit, basic and diluted	\$ 0.40	\$ 0.33	\$ 0.97	\$ 0.87
Weighted average number of Trust Units	48,960,661	31,499,481	40,728,537	31,477,064

Consolidated Statements of Cash Flows

(unaudited) (\$000s)	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Cash provided by (used in):				
Operating:				
Net income	\$ 19,373	\$ 10,306	\$ 39,599	\$ 27,495
Items not involving cash:				
Depletion and depreciation	18,792	6,367	38,118	19,139
Future income tax provision	-	311	-	376
Accretion of asset retirement obligation	63	59	185	172
Trust Units issued in lieu of management fee	666	366	1,508	1,035
Expenditures on reclamation	(1)	(17)	(70)	(43)
Funds generated from operations	38,893	17,392	79,340	48,174
Changes in non-cash working capital	(11,384)	1,697	(20,651)	(1,287)
	27,509	19,089	58,689	46,887
Financing:				
Issue of Trust Units, net of issue costs	-	-	258,935	-
Long-term debt	(2,000)	-	91,000	(1,000)
Distributions paid	(21,543)	(14,176)	(50,371)	(38,404)
	(23,543)	(14,176)	299,564	(39,404)
Investing:				
Corporate acquisition	-	(3,048)	-	(3,048)
Property and royalty acquisitions	-	116	(351,705)	(214)
Development expenditures	(4,059)	(2,278)	(6,351)	(3,928)
Increase in reclamation fund	(105)	(86)	(246)	(267)
	(4,164)	(5,296)	(358,302)	(7,457)
Increase (decrease) in cash	(198)	(383)	(49)	26
Cash, beginning of period	215	466	66	57
Cash, end of period	\$ 17	\$ 83	\$ 17	\$ 83

Notes to Interim Consolidated Financial Statements

For the period ended September 30, 2005

1. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Freehold Royalty Trust (“Freehold”) have been prepared by management in accordance with Canadian generally accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2004, unless otherwise identified. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in Freehold’s annual report for the year ended December 31, 2004.

2. BUSINESS COMBINATION

On May 10, 2005, Freehold closed the acquisition of Petrovera Resources, a general partnership that owns certain royalty, mineral and working interests. The acquisition cost of \$351.7 million (net of adjustments) was funded partially with a concurrent equity financing consisting of 13.5 million Trust Units at \$15.55 per Trust Unit and a private placement to the vendor of 3.9 million Trust Units at \$15.55 per Trust Unit for net proceeds of \$258.9 million. The remaining cost of \$92.8 million was financed utilizing Freehold’s credit facilities. The acquisition was accounted for using the purchase method of accounting with the results of operations being included from May 10, 2005.

The fair value of the acquisition costs are allocated as follows:

(\$000s)

Petroleum and natural gas interests	351,705
Asset retirement obligations	(19)

The above purchase price equation has not been finalized and is subject to certain revenue adjustments.

3. LONG-TERM DEBT

Freehold has a \$150.0 million extendible revolving term credit facility, extendible annually, on which \$118.0 million was drawn at September 30, 2005. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period. In addition, Freehold has available a \$15.0 million extendible revolving operating facility. Borrowings under the facilities bear interest at the Bank’s prime lending rate, bankers’ acceptance or LIBOR rates plus applicable margins, ranging from 85 to 140 basis points and standby fees. The facilities are secured with \$300.0 million demand debentures over Freehold’s petroleum and natural gas assets.

Interest paid during the nine months ended September 30, 2005, was \$2,192,000 (2004 – \$458,000) and for the current quarter was \$1,074,000 (2004 – \$147,000).

4. UNITHOLDERS' CAPITAL

	September 30, 2005		December 31, 2004	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	31,544,236	298,936	31,454,236	297,508
Issued for cash	17,363,520	270,003	–	–
Less: Issue expenses	–	(11,068)	–	–
Issued in lieu of management fee	88,171	1,508	90,000	1,428
Balance, end of period	48,995,927	559,379	31,544,236	298,936

5. ASSET RETIREMENT OBLIGATION

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 \$4.2 million, with the undiscounted value being \$10.0 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.

(\$000s)	September 30, 2005	December 31, 2004
Balance, beginning of period	\$ 3,937	\$ 3,606
Liabilities incurred	154	156
Liabilities added upon acquisition	19	–
Liabilities settled	(70)	(57)
Accretion expense	185	232
Balance, end of period	\$ 4,225	\$ 3,937

6. RELATED PARTY TRANSACTIONS

For the quarter, Freehold issued 35,654 Trust Units in payment for the management fee to Rife Resources Management Ltd. ("the Manager"). The total for the nine months ended September 30, 2005, was 88,171 Trust Units.

For the nine months ended September 30, 2005, the Manager charged the Trust \$2,248,000 in general and administrative costs. At September 30, 2005, there was \$480,000 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. The fees were \$5,304,000 for the nine months ended September 30, 2005, which was included as a cost of acquiring Petrovera Resources.

7. COMPARATIVE FIGURES

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

Corporate Information

DIRECTORS

D. Nolan Blades ⁽¹⁾⁽²⁾⁽³⁾

President
Sunny Gables Holdings Ltd.

Harry S. Campbell, Q.C. ⁽³⁾

Managing Partner
Burnet, Duckworth & Palmer, LLP

Tullio Cedraschi

President & Chief Executive Officer
CN Investment Division

Peter T. Harrison ⁽¹⁾⁽³⁾

Senior Vice-President
Montrusco Bolton Inc.

Dr. P. Michael Maher ⁽¹⁾⁽²⁾

Professor, Haskayne School of Business
University of Calgary

David J. Sandmeyer

President & Chief Executive Officer
Rife Resources Ltd.

William W. Siebens ⁽²⁾

President & Chief Executive Officer
Candor Investments Ltd.

- (1) Audit Committee
- (2) Governance Committee
- (3) Reserves Committee

2005 CASH DISTRIBUTIONS ⁽¹⁾

Record Date	Payment Date	Per Trust Unit
December 31, 2004	January 15, 2005	\$0.12
January 31, 2005	February 15, 2005	\$0.12
February 28, 2005	March 15, 2005	\$0.17 ⁽²⁾
March 31, 2005	April 15, 2005	\$0.12
April 30, 2005	May 15, 2005	\$0.12
May 31, 2005	June 15, 2005	\$0.17 ⁽²⁾
June 30, 2005	July 15, 2005	\$0.12
July 31, 2005	August 15, 2005	\$0.12
August 31, 2005	September 15, 2005	\$0.20 ⁽²⁾
September 30, 2005	October 15, 2005	\$0.14
October 31, 2005	November 15, 2005	\$0.14
November 30, 2005	December 15, 2005	<u>\$0.24</u> ⁽²⁾
Total, 2005 taxation year:		<u>\$1.78</u>

- (1) For Canadian residents, approximately 20% of distributions to Unitholders will be tax-deferred in 2005 and 80% will be taxable as other income. Tax information and historical distributions are available on our website at www.freeholdtrust.com.
- (2) Payment includes quarterly top-up.

OFFICERS

William W. Siebens

Chairman

David J. Sandmeyer

President & Chief Executive Officer

J. Frank George

Vice-President, Exploitation

Darren G. Gunderson

Controller

Joseph N. Holowisky

Vice-President, Finance & Administration
Chief Financial Officer and Secretary

William O. Ingram

Vice-President, Production

Michael J. Okrusko

Vice-President, Land

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WEBSITE

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STOCK EXCHANGE LISTING

Toronto Stock Exchange

Trading Symbol: FRU.UN

2005 THIRD QUARTER

TRADING SUMMARY

High – \$19.30

Low – \$15.99

Close – \$18.68

Volume – 9,980,028

Trust Units Outstanding – 48.9 million

Sept. 30 Market Capitalization – \$913 million

TRUSTEE & TRANSFER AGENT

Computershare Trust Company of Canada

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