Freehold
ROYALTY TRUST

Q4

400, 144 – 4TH AVENUE S.W.
CALGARY, ALBERTA T2P 3N4
TELEPHONE: 403 . 221 . 0802
FAX: 403 . 221 . 0888

NEWS RELEASE & QUARTERLY REPORT

TSX: FRU.UN
CUSIP: 355904103

Freehold Royalty Trust Announces 2005 Fourth Quarter and Year End Results and 2005 Year End Reserves

CALGARY, ALBERTA, (CCNMatthews – February 22, 2006) – Freehold Royalty Trust (Freehold or the Trust) (TSX:FRU.UN) today announced results for the period ended December 31, 2005.

FOURTH QUARTER HIGHLIGHTS

- Production averaged 8,739 barrels of oil equivalent (boe) per day, up 57% from the fourth quarter of 2004.
- Price realizations averaged $54.95 per boe, 43% higher than a year ago.
- Operating netback averaged $51.56 per boe, up 49% from the same period last year.
- Funds generated from operations were $0.79 per Trust Unit, up 55% from the fourth quarter of 2004.
- Distributions to Unitholders in the fourth quarter totalled $0.64 per Trust Unit, 31% higher than last year.
- Proved plus probable net reserves increased 44% to 30.5 million boe at December 31, 2005.
- Reserve additions of 13.8 million boe during 2005 replaced annual production by 428%.
- At forecast 2006 production levels, our reserve life index is 9.9 years.
- The regular monthly distribution remains fixed at $0.18 per Trust Unit.

Freehold's production remains 100% unhedged. Our full exposure to high crude oil prices, combined with increased production from the Petrovera acquisition completed in 2005, resulted in record financial and operating results.

Results at a Glance	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Financial ($000s, except as noted)						
Gross revenue	**44,555**	19,936	123%	**136,914**	78,491	74%
Operating income	**41,452**	17,781	133%	**126,793**	69,654	82%
Net income	**18,747**	9,397	99%	**58,346**	36,892	58%
Per Trust Unit, basic and diluted ($)	**0.38**	0.30	27%	**1.36**	1.17	16%
Funds generated from operations	**38,694**	16,139	140%	**118,034**	64,313	84%
Per Trust Unit ($)	**0.79**	0.51	55%	**2.76**	2.04	35%
Distributions to Unitholders	**31,366**	15,449	103%	**84,810**	54,490	56%
Per Trust Unit ($) (1)	**0.64**	0.49	31%	**1.92**	1.73	11%
Long-term debt	**107,000**	27,000	296%	**107,000**	27,000	296%
Unitholders' equity	**399,471**	164,822	142%	**399,471**	164,822	142%
Operating						
Average daily production (boe/d)	**8,739**	5,575	57%	**7,636**	5,588	37%
Average price realizations ($/boe)	**54.95**	38.37	43%	**48.53**	37.91	28%
Operating netback ($/boe)	**51.56**	34.67	49%	**45.49**	34.05	34%

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

Message to Unitholders

Freehold achieved record financial and operating results in the fourth quarter of 2005, buoyed by a 57% increase in oil and gas production and a 43% increase in average price realizations compared with the fourth quarter of 2004. For the full year, net income rose 16% and funds generated from operations rose 35% on a per Trust Unit basis. As well, operating costs and general and administrative expenses were lower on a per barrel of oil equivalent (boe) basis, reflecting the benefit of the additional royalty production from the Petrovera acquisition that we completed in May of 2005.

Distributions with respect to 2005 operations totalled a record $1.92 per Trust Unit. The Trust earned more taxable income in 2005 than the amounts distributed to Unitholders during the year. Our Trust Indenture requires that any taxable income earned in the Trust that exceeds the amount paid in distributions automatically becomes payable to Unitholders. As a result, all distributions with respect to 2005 are 100% taxable. As announced on February 9, 2006, Unitholders will receive an additional distribution of $0.08 per Trust Unit, arising from the excess taxable income earned in 2005. This amount is included in the $1.92 mentioned above.

Freehold Royalty Trust is now included in the S&P/TSX Composite Index. Standard & Poor's had previously announced it intended to include income trusts in the S&P/TSX Composite Index at 50 per cent of their full float adjusted weight on December 16, 2005 and at full weighting on the March 17, 2006 market close.

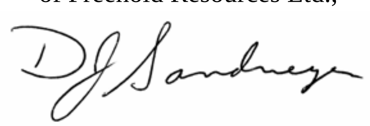
Our reserves increased 44% year-over-year. Natural gas reserves now account for approximately 37% of reserves, up from 29% one year ago. We replaced 428% of annual production through acquisitions and development activities (excluding technical revisions and economic factors), at an average cost of $26.02 per boe in 2005. Our reserve life index is 9.9 years and our net asset value (discounted at 10%) is $13.85 per Trust Unit, up 55% over 2004.

A record 1,001 gross (34.1 equivalent net) wells were drilled on our lands in 2005. Similar to 2005, industry drilling is predicted to continue at a strong pace, with 25,000 wells forecast for 2006. High activity levels have created high demand for oilfield services, and the industry is experiencing rising operating costs, higher finding and development costs, and a shortage of experienced people. As 80% of our production is from royalties, we are somewhat sheltered from these inflationary effects, however, the delays being experienced throughout the industry, particularly for service rigs and mechanical services, are having an impact on our production volumes. We estimate that approximately 200 boe per day of production is currently waiting to come on stream. Nevertheless, the fundamental outlook for oil and gas producers is positive for 2006 and through the remainder of the decade.

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.

On November 23, 2005, the Government of Canada ended the consultation process initiated on September 8, 2005, announcing no changes to the tax treatment of income trusts and flow-through entities and a reduction in personal income taxes on dividends. The decision removes the uncertainty surrounding income trust taxation and levels the playing field between corporations and trusts by establishing a better balance between the tax treatment of these entities.

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



David J. Sandmeyer
President & Chief Executive Officer

SUMMARY OF RESERVES

Our oil and gas reserves, as at December 31, 2005, were independently evaluated by Trimble Engineering Associates Ltd. The evaluation was conducted in accordance with National Instrument 51-101 (NI 51-101). Our Reserves Committee met with the reserve evaluators to review their findings and procedures and the reserve report has been accepted by the Board.

At December 31, 2005, reserves were assigned to 19,468 wells. Net reserves totalled 30.5 million boe, up 44% from year-end 2004. We replaced 428% of annual production through acquisitions and development activities (excluding technical revisions and economic factors). Technical revisions reduced proved plus probable reserves by 1.3 million boe. Approximately half of the reduction related to prior year ownership changes, with the remainder due to performance issues on oil properties in west central and southeast Saskatchewan, and southeast Alberta.

The average cost of reserve replacement was $26.02 per boe in 2005, compared with $12.88 per boe in 2004. The acquired reserves were royalty properties which have a greater economic value than working interests and therefore command a higher market price. Based on 2005 net reserves and the evaluator's forecast of 2006 net production (which includes the benefit from the Petrovera acquisition for the full year), Freehold's reserve life index is 9.9 years.

The present value of our net proved plus probable oil and gas reserves, discounted at 10%, is $743 million, up 154%. The increase relates primarily to the reserves acquired during 2005 and to higher future price expectations.

Net Oil and Gas Reserves (1) as at December 31, 2005	Proved				Proved Plus Probable
	Developed Producing	Developed Non-producing	Undeveloped	Total Proved	
Light and medium oil (Mbbls)	4,722	0	0	4,722	6,641
Heavy oil (Mbbls)	6,642	0	239	6,881	10,813
Natural gas (MMcf)	45,105	131	11	45,247	68,152
NGLs (Mbbls)	1,267	0	1	1,268	1,717
Total (Mboe)	20,149	22	241	20,412	30,530
Reserve life index (years) (2)	7.4	—	—	7.4	9.9

(1) Columns may not add due to rounding.

(2) RLI is calculated by dividing the evaluators forecast of 2006 net production into the remaining net reserves.

Reconciliation of Net Oil and Gas Reserves (1)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)	Net Present Value (2) ($000s)
December 31, 2004	14,678	6,485	21,163	292,247
Extensions	413	500	913	35,187
Technical revisions	158	(1,423)	(1,265)	(15,396)
Discoveries	16	16	32	1,450
Acquisitions (3)	8,323	4,566	12,889	224,521
Dispositions	(27)	(8)	(35)	(385)
Economic factors	32	28	60	276,887
2005 production	(3,181)	(46)	(3,227)	(71,679)
December 31, 2005	20,412	10,118	30,530	742,832
Change over prior year	5,734	3,633	9,367	450,585

(1) Columns may not add due to rounding.

(2) Net present value of proved plus probable reserves based on forecast prices and costs, discounted at 10% before tax, including Alberta Royalty Credit. Based on the December 31, 2005 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

(3) Petrovera Resources, effective January 1, 2005.

Analysis of Development and Acquisition Costs	**2005**	2004	2003	Three-Year Results
Development expenditures ($000s)	**7,982**	5,823	5,894	19,699
Change in future development capital estimates ($000s)	**235**	(2,593)	3,429	1,071
Net reserve additions by development (Mboe)	**945**	817	911	2,673
Development costs ($/boe) (1)	**8.70**	3.95	10.23	7.77
Acquisition expenditures ($000s)	**351,705**	12,881	3,386	367,972
Net reserve additions by acquisition (Mboe)	**12,889**	434	209	13,532
Acquisition costs ($/boe)	**27.29**	29.68	16.20	27.19
Total expenditures ($000s)	**359,687**	18,704	9,280	387,671
Change in future development capital estimates ($000s)	**235**	(2,593)	3,429	1,071
Net reserve additions (Mboe)	**13,834**	1,251	1,120	16,205
Development and acquisition costs ($/boe)	**26.02**	12.88	11.35	23.99

(1) Development costs equal development expenditures plus change in future capital, divided by reserves added.

In 2005, our recycle ratio was 1.7, contributing to a three-year average recycle ratio of 1.6. The recycle ratio is a key measure of the efficiency in which new reserves are added and is indicative of the value created by investment activities. The higher the recycle ratio, the better the profitability of our investments.

Recycle Statistics ($ per boe, except as noted)	**2005**	2004	2003	Three-Year Results
Operating netback (1) (4)	**45.49**	34.05	30.51	37.56
Development and acquisition costs (2) (4)	**26.02**	12.88	11.35	23.99
Recycle ratio (times) (3)	**1.7**	2.6	2.7	1.6

(1) Operating netback is calculated as total revenue, less operating costs and royalties, net of Alberta Royalty Credit.

(2) Development expenditures, plus change in future capital, plus acquisition costs, divided by net reserves added through development and acquisition activities.

(3) Operating net back divided by the average cost of acquiring and developing new reserves.

(4) Operating netback is based on gross production, while development and acquisition costs are based on net reserves.

SUMMARY OF LAND HOLDINGS

Our land holdings increased substantially in 2005, primarily as a result of the Petrovera acquisition. At December 31, 2005, our land holdings encompassed more than two million gross acres, including 555,171 gross acres of undeveloped land. Our undeveloped land was independently evaluated by Seaton-Jordon & Associates, effective December 31, 2005, at $14.1 million.

Summary of Land Holdings	December 31		
(gross acres) (1)	**2005**	2004	Change
Mineral title and gross overriding royalty land	**1,808,704**	867,155	109%
Working interest land	**197,241**	199,874	-1%
Total	**2,005,945**	1,067,029	88%
Undeveloped land	**555,171**	291,729	90%

(1) Gross acreage represents the total number of acres in which we have an interest.

NET ASSET VALUE

Freehold's net asset value as of December 31, 2005 (discounted at 10%, before tax) was $13.85 per Trust Unit, up from $8.92 at year-end 2004. Year over year, the major variances in the composition of asset value were increased bank debt, reserves added through the Petrovera acquisition and higher future price expectations.

Net Asset Value as at December 31, 2005 [1]	Discounted at			
($000s, except unit data)	0%	5%	10%	15%
Present value of oil and gas reserves [2]	1,508,055	974,721	742,832	612,527
Present value of potash reserves [3]	47,258	19,520	11,044	7,613
Undeveloped land [4]	14,144	14,144	14,144	14,144
Reclamation fund	1,964	1,964	1,964	1,964
Working capital	16,281	16,281	16,281	16,281
Bank debt	(107,000)	(107,000)	(107,000)	(107,000)
Net asset value	1,480,702	919,630	679,265	545,529
Trust Units outstanding	49,031,581	49,031,581	49,031,581	49,031,581
Net asset value per Trust Unit	30.20	18.76	13.85	11.13

(1) Columns may not add due to rounding.

(2) Evaluated by Trimble Engineering Associates Ltd. and includes Alberta Royalty Tax Credit.

(3) Potash reserves, evaluated by Rife Resources Ltd., are not subject to NI 51-101.

(4) Evaluated by Seaton-Jordan & Associates Ltd., effective December 31, 2005.

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 twelve months ended December 31, 2005 and previous periods, and the outlook for Freehold based on information available as at February 22, 2006. 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 December 31, 2004 and December 31, 2005, 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 February 22, 2006, 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. Subject to our obligations under applicable law, we do not undertake to update or revise these forward-looking statements, whether as a result of new information, future events, or otherwise.

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 2005 required a corresponding increase in our revenue accruals. The increase is reflected in higher accounts receivables.

SUPPLEMENTAL DISCLOSURE

We believe that operating income, netback and funds generated from operations are useful supplemental measures to analyze operating performance, leverage and liquidity. Operating income, which is gross revenue less royalty expense and operating expense, represents the results of operations before general and administrative, interest, taxes and non-cash expenses. 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. Funds generated from operations is derived from our Consolidated Statements of Cash Flows. It represents cash provided by operating activities, before changes in non-cash working capital. Operating income, netback, and funds generated from operations 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

Additional royalty production and higher average selling prices led to record income and funds generated from operations for both the fourth quarter and the full year 2005.

Net Income and Funds Generated From Operations	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Net income ($000s)	**18,747**	9,397	99%	**58,346**	36,892	58%
Per Trust Unit, basic and diluted ($)	**0.38**	0.30	27%	**1.36**	1.17	16%
Funds generated from operations ($000s)	**38,694**	16,139	140%	**118,034**	64,313	84%
Per Trust Unit ($)	**0.79**	0.51	55%	**2.76**	2.04	35%

TRUST UNITS OUTSTANDING

On December 31, 2005, we issued 35,654 Trust Units in payment of the management fee. As at December 31, 2005 and February 22, 2006, there were 49,031,581 Trust Units outstanding. There are no options outstanding under the Trust Unit option plan.

Trust Units Outstanding	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Weighted average	**48,996,315**	31,521,981	55%	**42,812,470**	31,488,355	36%
At period end	**49,031,581**	31,544,236	55%	**49,031,581**	31,544,236	55%

The following table summarizes our performance for the fourth quarter of 2005 and 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. In addition, the acquisition of Petrovera Resources on May 10, 2005 had a positive impact on our financial results. The Petrovera contribution is partially reflected in the second quarter (52 days of production) and fully reflected in the last two quarters of 2005.

Quarterly Results	**2005**				2004			
($000s, except as noted)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Financial								
Revenue, net of royalty expense	**43,364**	**42,867**	**27,922**	**19,170**	19,204	19,994	19,066	17,250
Funds generated from operations	**38,694**	**38,893**	**24,344**	**16,103**	16,139	17,392	16,407	14,375
Per Trust Unit ($)	**0.79**	**0.79**	**0.59**	**0.51**	0.51	0.55	0.52	0.46
Distributions to Unitholders	**31,366**	**22,527**	**17,981**	**12,936**	15,449	14,808	12,593	11,640
Per Trust Unit ($) (1)	**0.64**	**0.46**	**0.41**	**0.41**	0.49	0.47	0.40	0.37
Payout ratio (%)	**81**	**58**	**74**	**80**	96	85	77	81
Net income	**18,747**	**19,373**	**10,858**	**9,368**	9,397	10,306	9,515	7,674
Per Trust Unit, basic and diluted ($)	**0.38**	**0.40**	**0.26**	**0.30**	0.30	0.33	0.30	0.24
Long-term debt	**107,000**	**118,000**	**120,000**	**27,000**	27,000	17,000	17,000	18,000
Trust Units outstanding (000s) (2)	**49,032**	**48,996**	**48,960**	**31,567**	31,544	31,522	31,499	31,477
Operating								
Daily production (boe/d)	**8,739**	**8,974**	**7,279**	**5,502**	5,575	5,447	5,757	5,577
Average selling price ($/boe)	**54.95**	**52.61**	**42.42**	**39.47**	38.37	40.96	37.37	35.00
Operating netback ($/boe)	**51.56**	**49.89**	**39.61**	**36.18**	34.67	36.85	33.57	31.18
Benchmark Prices								
WTI crude oil (US$/bbl)	**60.02**	**63.19**	**53.20**	**49.84**	48.28	43.88	38.31	35.14
Exchange rate (Cdn$/US$)	**0.85**	**0.83**	**0.80**	**0.82**	0.82	0.77	0.74	0.76
Edmonton Par (Cdn$)	**71.17**	**76.51**	**65.76**	**61.45**	57.70	56.25	50.60	45.60
Light/heavy oil differential (Cdn$/bbl)	**28.14**	**20.79**	**24.17**	**22.48**	21.60	14.29	13.29	10.67
Bow River/Hardisty (Cdn$/bbl)	**43.03**	**55.72**	**41.59**	**38.97**	36.10	41.96	37.31	34.93
AECO natural gas (Cdn$/Mcf)	**11.68**	**8.17**	**7.38**	**6.69**	7.08	6.66	6.80	6.61
Unit Trading Performance								
High ($)	**18.98**	**19.30**	**17.63**	**18.49**	18.42	16.97	15.80	16.30
Low ($)	**15.15**	**15.99**	**14.25**	**15.50**	15.75	14.57	14.65	14.02
Close ($)	**18.81**	**18.68**	**15.99**	**16.10**	17.45	16.25	15.00	14.75
Volume (000s)	**7,611**	**9,980**	**8,311**	**2,418**	4,252	1,768	3,149	2,399

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

(2) At period end.

DISTRIBUTIONS TO UNITHOLDERS AND UNITHOLDER TAXATION

Distributions to Unitholders for the fourth quarter of 2005 were $31.4 million, or $0.64 per Trust Unit, compared with $15.4 million, or $0.49 per Trust Unit, in the fourth quarter of 2004. As a result of the Petrovera acquisition, royalty income contributed 92% of distributions, up from 88% in the fourth quarter of 2004. 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. This increase in accounts receivable is included in changes in working capital.

Distributions to Unitholders ($000s, except as noted)	Three Months Ended December 31		Twelve Months Ended December 31	
	2005	2004	**2005**	2004
Funds generated from operations	**38,694**	16,139	**118,034**	64,313
Net reclamation fund contribution	**(72)**	(90)	**(318)**	(357)
Capital expenditures	**(1,631)**	(1,895)	**(7,982)**	(5,823)
Debt additions (repayment)	**(11,000)**	10,000	**80,000**	9,000
Proceeds from Trust Unit issuance	—	—	**258,935**	—
Corporate acquisition	—	—	—	(3,048)
Property and royalty acquisitions	—	(9,799)	**(351,705)**	(10,013)
Changes in working capital	**5,375**	1,094	**(12,154)**	418
Distributions to Unitholders	**31,366**	15,449	**84,810**	54,490
Accumulated, beginning of period	**351,658**	282,765	**298,214**	243,724
Accumulated, end of period	**383,024**	298,214	**383,024**	298,214
Distributions per Trust Unit [(1)] ($)	**0.64**	0.49	**1.92**	1.73
Accumulated, beginning of period	**11.56**	9.79	**10.28**	8.55
Accumulated, end of period	**12.20**	10.28	**12.20**	10.28

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

Payout Ratio [(1)] ($ per Trust Unit, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Funds generated from operations	**38,694**	16,139	140%	**118,034**	64,313	84%
Distributions to Unitholders	**31,366**	15,449	103%	**84,810**	54,490	56%
Payout ratio	**81%**	96%	-16%	**72%**	85%	-15%

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

On November 23, 2005, the Government of Canada ended the consultation process initiated on September 8, 2005, announcing no changes to the tax treatment of income trusts and flow-through entities and a reduction in personal income taxes on dividends. The decision removes the uncertainty surrounding income trust taxation and levels the playing field between corporations and trusts by establishing a better balance between the tax treatment of these entities.

For Canadian tax purposes, 100% of distributions paid or payable in 2005 are taxable as income, unless held in a registered plan, such as a Registered Retirement Savings Plan, a Registered Retirement Income, a Deferred Profit Sharing Plan or a Registered Education Savings Plan.

Distributions with respect to the 2005 operations totalled $1.92 per Trust Unit. However for the 2005 taxation year, Unitholders should report total income of $2.04 per Trust Unit. The difference of $0.12 per Trust Unit is attributable to the monthly distribution of $0.12 declared in December 2004 and paid on January 15, 2005.

The 2005 tax slips will include distributions for a 13-month period, as provided in the following table.

2005 Tax Information Record Date	Payment Date	Taxable Amount Box 26 (Other Income)	Tax-Deferred Amount (Return of Capital)	Total Cash Distribution Paid CDN $
December 31, 2004	January 15, 2005	$0.12	$0.00	$0.12
January 31, 2005	February 15, 2005	$0.12	$0.00	$0.12
February 28, 2005	March 15, 2005	$0.17	$0.00	$0.17
March 31, 2005	April 15, 2005	$0.12	$0.00	$0.12
April 30, 2005	May 15, 2005	$0.12	$0.00	$0.12
May 31, 2005	June 15, 2005	$0.17	$0.00	$0.17
June 30, 2005	July 15, 2005	$0.12	$0.00	$0.12
July 31, 2005	August 15, 2005	$0.12	$0.00	$0.12
August 31, 2005	September 15, 2005	$0.20	$0.00	$0.20
September 30, 2005	October 15, 2005	$0.14	$0.00	$0.14
October 31, 2005	November 15, 2005	$0.14	$0.00	$0.14
November 30, 2005	December 15, 2005	$0.24	$0.00	$0.24
December 31, 2005	January 15, 2006	$0.18	$0.00	$0.18
February 20, 2006	March 15, 2006	$0.08	$0.00	$0.08 (1)
Total paid or payable in 2005		$2.04	$0.00	$2.04

(1) Additional income payable in respect of 2005 income.

Upcoming Distributions **Record Date**	**Payment Date**	**Distribution Amount** ($/Trust Unit)
February 20, 2006	March 15, 2006	0.08 (1)
February 28, 2006	March 15, 2006	0.18
March 31, 2006	April 15, 2006	0.18 (2)
April 30, 2006	May 15, 2006	0.18 (2)
May 31, 2006	June 15, 2006	0.18 (2)

(1) Special distribution as a result of excess taxable income earned in 2005. In settlement, holders of record on February 20, 2006, will receive a special distribution of $0.08 per Trust Unit. To the extent that Trust Units have been disposed of between December 31, 2005 and February 20, 2005, this additional $0.08 will increase a Unitholder's adjusted cost base. For investors who were not Unitholders on December 31, 2005, but were Unitholders of record on February 20, 2006, the $0.08 per Trust Unit receipt is not taxable in 2006, but reduces the adjusted cost base of the 2006 acquisition.

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

PRODUCTION

Average daily production volumes were 57% higher in the fourth quarter and 37% higher in the year ended December 31, 2005, compared with the same periods last year. Results for the quarter included prior period adjustments of approximately 200 boe per day of royalty production, which reduced reported production in the current quarter. Reflecting the Petrovera acquisition, royalty production volumes contributed 80% of volumes in the fourth quarter, up from 66% a year ago. Our production profile in the fourth quarter of 2005 was 39% natural gas, 4% natural gas liquids (NGL), 20% light and medium oil, and 37% heavy oil (on a boe basis).

Demand for oilfield equipment and services remains high throughout western Canada. Although royalty volumes were higher for the quarter, approximately 100 boe per day of royalty production was deferred until the first quarter of 2006 due to delays in bringing on new production.

Working interest production was 9% lower than the fourth quarter of 2004. The annual turnaround (plant maintenance) at Hayter in October resulted in a 100 boe per day reduction compared with last year, as the 2004 turnaround was conducted in June. As with royalty properties, the lack of services deferred production of approximately 30 boe per day at Hayter into 2006, and it is estimated that a further 100 boe per day of working interest production was deferred to early 2006.

Average Daily Production	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Royalty lands						
Oil (bbls/d)	**3,699**	2,274	63%	**3,185**	2,206	44%
NGL (bbls/d)	**302**	228	32%	**284**	217	31%
Natural gas (Mcf/d)	**18,089**	7,054	156%	**14,501**	7,726	88%
Oil equivalent (boe/d)	**7,016**	3,678	91%	**5,885**	3,711	59%
Working interest properties						
Oil (bbls/d)	**1,290**	1,406	-8%	**1,303**	1,388	-6%
NGL (bbls/d)	**66**	70	-6%	**61**	66	-8%
Natural gas (Mcf/d)	**2,202**	2,528	-13%	**2,320**	2,544	-9%
Oil equivalent (boe/d)	**1,723**	1,897	-9%	**1,751**	1,877	-7%
Total Trust						
Oil (bbls/d)	**4,989**	3,680	36%	**4,488**	3,594	25%
NGL (bbls/d)	**368**	298	23%	**345**	283	22%
Natural gas (Mcf/d)	**20,291**	9,582	112%	**16,821**	10,270	64%
Oil equivalent (boe/d)	**8,739**	5,575	57%	**7,636**	5,588	37%
Number of days in period (days)	**92**	92	0%	**365**	366	0%
Total volumes during period (Mboe)	**804**	513	57%	**2,787**	2,045	36%
Potash production (tonnes/d)	**11.1**	8.5	31%	**9.7**	7.6	28%

BENCHMARK PRICES

Commodity prices remained high in the fourth quarter, and the Canadian dollar was also higher compared with last year. While the price for Bow River/Hardisty heavy oil rose 19%, the light/heavy oil differential widened significantly – being 30% higher in the fourth quarter and 60% higher on the full year. The differential is significant for Freehold, as two-thirds of our oil production (37% of our total boe production) is heavy oil.

Average Benchmark Prices	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
WTI crude oil (US$/bbl)	**60.02**	48.28	24%	**56.56**	41.40	37%
US$/Cdn$ exchange rate	**0.8524**	0.8195	4%	**0.8260**	0.7698	7%
Edmonton Par crude oil (Cdn$/bbl)	**71.17**	57.71	23%	**68.72**	52.54	31%
Light/heavy oil differential (Cdn$/bbl)	**28.14**	21.60	30%	**23.90**	14.94	60%
Bow River/Hardisty (Cdn$/bbl)	**43.03**	36.10	19%	**44.83**	37.60	19%
AECO natural gas (Cdn$/Mcf)	**11.68**	7.08	65%	**8.48**	6.79	25%

FREEHOLD'S REALIZED PRICES

On a boe basis, our average price realizations were 43% higher than the fourth quarter of 2004 and 28% higher than the 2004 average. Petrovera production increased the natural gas component of our product mix to 39% from 29% in the fourth quarter 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.

Average Selling Prices	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Oil ($/bbl)	**45.79**	38.09	20%	**46.65**	38.08	23%
NGL ($/bbl)	**58.67**	40.62	44%	**50.58**	37.29	36%
Oil and NGL ($/bbl)	**46.67**	38.28	22%	**46.93**	38.03	23%
Natural gas ($/Mcf)	**11.34**	6.44	76%	**8.55**	6.28	36%
Oil equivalent ($/boe)	**54.95**	38.37	43%	**48.53**	37.91	28%
Potash ($/tonne)	**205.76**	182.69	13%	**213.28**	167.37	27%

DEVELOPMENT ACTIVITIES

The record pace of drilling continued in the final quarter of 2005. The industry as a whole drilled 24,800 wells in 2005, just shy of the record 25,000 wells drilled in 2004. Mirroring this activity, a record 1,001 gross (34.1 equivalent net) wells were drilled on our lands in 2005.

In the current pricing environment, industry activity levels are anticipated to remain robust. The Petroleum Services Association of Canada (PSAC) predicts that more than 25,000 wells will be drilled in western Canada in 2006. Their forecast is based on crude oil prices of US$60.00 per barrel (WTI) and natural gas prices of Cdn.$9.50 per Mcf (AECO). PSAC also cited the ongoing lack of skilled labour as a key issue facing the industry in 2006.

ROYALTY INTEREST LANDS

A total of 169 wells were drilled on our royalty lands in the fourth quarter, including 43 unitized wells. On an equivalent net basis, this is 6.4 wells, up 121% from the fourth quarter of last year. The increase is attributable to drilling on the Petrovera lands in 2005. There are currently 92 (4.6 equivalent net) licensed drilling locations on our royalty lands, compared with 41 (1.3 equivalent net) locations at this time last year, signalling a very strong start to 2006. Drilling on our royalty wells occurs at no cost to Freehold.

Royalty Interest Lands Drilling Summary (1)	Three Months Ended December 31			Twelve Months Ended December 31		
(includes unitized wells)	**2005**	2004	Change	**2005**	2004	Change
Gross wells	**169**	146	16%	**884**	671	32%
Equivalent net wells (2)	**6.4**	2.9	121%	**25.0**	12.3	103%
Net success rate	**99%**	99%		**99%**	99%	

(1) Includes drilling on the Petrovera lands from January 1, 2005 (the effective date of the acquisition), except wells drilled in Ontario.

(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 fourth quarter of 2005, we spent $1.6 million on facilities and the drilling of 24 (2.0 net) wells. This activity resulted in 11 oil wells, 11 natural gas wells, and 2 unclassified wells. The major areas of activity were at Wordsworth and Queensdale, in Southeast Saskatchewan, where four oil wells were drilled. Gas wells were drilled at Brownfield, Eymore and Pembina. Capital was also spent completing wells drilled at LaGlace and Willesden Green in the third quarter. These areas will be the focus of our first quarter activity, as work continues to tie-in the new wells.

Working Interest Properties Drilling Summary	Three Months Ended December 31				Twelve Months Ended December 31			
	2005		2004		**2005**		2004	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**11**	**1.2**	9	0.3	**44**	**6.9**	32	3.6
Natural gas	**11**	**0.6**	31	1.3	**69**	**1.8**	57	1.8
Other	**2**	**0.2**	1	—	**4**	**0.4**	1	0
Total	**24**	**2.0**	41	1.6	**117**	**9.1**	90	5.4

REVENUE

We receive revenue from about 200 industry operators. Gross revenue more than doubled in the fourth quarter, to $44.6 million from $19.9 million in the same period last year. Higher production volumes, mainly from the Petrovera acquisition, accounted for roughly 70% of the increase, with the remainder due to higher commodity prices. Year over year, revenue was 74% higher than in 2004. Increased production volumes accounted for 63% of the revenue increase, with higher commodity prices accounting for the remainder.

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 December 31		Twelve Months Ended December 31	
	2005 vs. 2004	2004 vs. 2003	**2005 vs. 2004**	2004 vs. 2003
Oil and NGL				
Production increase (decrease)	**5,923**	(197)	**16,191**	(1,637)
Price increase (decrease)	**3,072**	3,571	**12,637**	7,896
Net increase (decrease)	**8,995**	3,374	**28,828**	6,259
Natural gas				
Production increase (decrease)	**11,175**	(488)	**20,345**	(1,314)
Price increase (decrease)	**4,326**	1,139	**8,531**	400
Net increase (decrease)	**15,501**	651	**28,876**	(914)
Other	**123**	42	**719**	(20)
Gross revenue increase (decrease)	**24,619**	4,067	**58,423**	5,325

EXPENSES

ROYALTIES PAID

Royalty expense rates on our working interest properties are tied to commodity prices and production volumes. In the fourth quarter, royalty expenses per boe increased 3%, due to higher commodity prices. Royalty expenses declined 12% year over year, reflecting the increase in royalty production volumes, which have no royalty expenses.

Royalty Expenses (net of Alberta Royalty Tax Credit)	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Working interest properties ($000s)	**1,191**	732	63%	**3,591**	2,977	21%
Per boe ($)	**7.51**	4.20	79%	**5.62**	4.33	30%
Royalty interest lands [1] ($000s)	**0**	0	—	**0**	0	—
Per boe ($)	**0**	0	—	**0**	0	—
Total royalty expenses ($000s)	**1,191**	732	63%	**3,591**	2,977	21%
Total Trust ($/boe)	**1.48**	1.43	3%	**1.29**	1.46	-12%

(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

On our working interest properties, which account for 20% of our production, operating expenses were up 48% in the fourth quarter and up 20% for the year. Record activity levels have created high demand for oilfield services, which has caused inflationary pressures throughout the oil and gas sector. The oil and gas industry in western Canada is experiencing rising operating costs, higher finding and development costs, and a shortage of experienced people. With 80% of our production from royalties, we are somewhat sheltered from these inflationary effects, because on royalty production, the operators pay royalties to us based on gross production revenue, before deduction of operating expenses. Overall, operating costs for the fourth quarter were $2.38 per boe, 14% lower than last year, reflecting higher royalty production. For 2005, operating expenses of $2.34 per boe were 18% lower than in 2004.

Operating Expenses	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Working interest properties ($000s)	**1,912**	1,423	34%	**6,530**	5,860	11%
Per boe ($)	**12.06**	8.16	48%	**10.22**	8.53	20%
Royalty interest lands [1] ($000s)	**0**	0	—	**0**	0	—
Per boe ($)	**0**	0	—	**0**	0	—
Total operating expenses ($000s)	**1,912**	1,423	34%	**6,530**	5,860	11%
Total Trust ($/boe)	**2.38**	2.77	-14%	**2.34**	2.87	-18%

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

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

G&A expenses for the fourth quarter of 2005 were $1.2 million, 41% higher than last year, reflecting an increase in the Manager's staff levels and rising costs associated with regulatory compliance and financial reporting. However, on a per boe basis, G&A expenses declined 10% compared with last year, as the Manager was able to administer the additional production volumes with minimal staff additions.

For the year ended December 31, 2005, the Manager charged the Trust $3.0 million in G&A costs. At December 31, 2005, there was $219,000 in accounts payable relating to these costs.

G&A Expenses	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
G&A expenses ($000s)	**1,222**	864	41%	**4,392**	3,502	25%
Per boe ($)	**1.52**	1.68	-10%	**1.58**	1.71	-8%
As a percentage of revenue	**2.7%**	4.3%	-37%	**3.2%**	4.5%	-29%

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 fourth quarter of 2005 was 35,654 Trust Units (2004 – 22,500 Trust Units). The ascribed value of the management fee was based on the closing price of the Trust Units on December 31, 2005. 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 ($000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Management fees (paid in Trust Units) (1)	**670**	393	70%	**2,178**	1,428	53%
Per boe ($)	**0.83**	0.77	8%	**0.78**	0.70	11%
Acquisition fees (2)	**0**	150		**5,306**	197	

(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 fourth quarter, interest expense totalled $1.1 million, or $1.42 per boe. For the full year, interest expense was 3.2 million or $1.13 per boe.

Interest Expenses ($000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Net interest expense	**1,141**	172	563%	**3,158**	635	397%
Per boe ($)	**1.42**	0.34	318%	**1.13**	0.31	265%

NETBACK

Our operating netback in the fourth quarter was $51.56 per boe, 49% higher than last year, reflecting higher commodity prices, and a higher percentage of royalty production, which has no associated royalty or operating expenses. To a lesser degree, our higher netback also reflects a higher percentage of natural gas in our product mix from the Petrovera acquisition. In 2005, the operating netback averaged $45.49, 34% higher than in 2004 for the same reasons. We do not have any commodity price or foreign currency hedges in place.

Operating Netback ($/boe)	Three Months Ended December 31			Twelve Months Ended December 31		
	2005	2004	Change	**2005**	2004	Change
Gross revenue (1)	**55.42**	38.87	43%	**49.12**	38.38	28%
Royalty expenses (2)	**1.48**	1.43	3%	**1.29**	1.46	-12%
Operating expenses	**2.38**	2.77	-14%	**2.34**	2.87	-18%
Operating netback	**51.56**	34.67	49%	**45.49**	34.05	34%

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

(2) Net of Alberta Royalty Tax Credit.

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 fourth quarter, we had no short-term debt outstanding and long-term debt was $107 million. We had working capital of $16.3 million, resulting in net debt of $90.7 million.

Debt Analysis	As at December 31		
($000s)	**2005**	2004	Change
Long-term debt	**107,000**	27,000	296%
Short-term debt	**0**	0	—
Total debt	**107,000**	27,000	296%
Less: working capital	**16,281**	4,128	294%
Net debt obligations	**90,719**	22,872	297%

At December 31, 2005, the Trust’s ratio of net debt (long-term debt less positive working capital) to trailing funds generated from operations was 0.8 to 1, compared with 0.4 to 1 at the end of 2004.

Financial Leverage and Coverage Ratios (1)	As at December 31		
	2005	2004	Change
Net debt to funds generated from operations (times)	**0.8**	0.4	100%
Net debt to distributions (times)	**1.1**	0.4	175%
Distributions to interest expense (times)	**26.9**	86.0	-69%
Net debt to net debt plus equity (%)	**18.5**	12.2	52%

(1) Funds generated from operations, 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 $12.2 million during the year. At December 31, 2005, working capital of $16.3 million was $5.4 million lower than at September 30, 2005, due to the increase in distributions payable to Unitholders at year-end.

Components of Working Capital ($000s)	**December 31 2005**	September 30 2005	June 30 2005	March 31 2005	December 31 2004
Cash	**192**	17	215	146	66
Accounts receivable	**35,728**	35,211	21,707	13,642	12,797
Current assets	**35,920**	35,228	21,922	13,788	12,863
Distributions payable to Unitholders	**12,748**	6,859	5,875	3,788	3,785
Accounts payable and accrued liabilities	**6,891**	6,713	4,593	3,829	4,950
Current liabilities	**19,639**	13,572	10,468	7,617	8,735
Working capital (1)	**16,281**	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. We do not incur any capital expenditures on our royalty properties. Capital expenditures on working interest properties totalled $1.6 million in the fourth quarter (2004 – $1.9 million). Capital expenditures in 2005 totalled $8.0 million (2004 – $5.8 million). Due to the delay in accessing oilfield services, approximately $1.7 million of anticipated capital spending has been carried over to 2006. Capital expenditures in 2006 are anticipated to be approximately $6.0 million.

DISTRIBUTION OUTLOOK

The regular monthly distribution is currently fixed at $0.18 per Trust Unit. For 2006, we estimate distributions of $2.16 per Trust Unit, based on monthly distributions of $0.18 per Trust Unit. 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 and a sensitivity analysis of the potential impact of key variables on distributions to Unitholders are provided 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 38% of our total boe production is heavy oil.

2006 Distribution Outlook and Key Assumptions

	February 22, 2006	November 9, 2005
Estimated cash distributions ($ per Trust Unit) (1)	**2.16**	2.16
Key assumptions		
Average daily production (boe/d)	**8,500**	8,600
Average WTI oil price (US$/bbl)	**60.75**	60.00
Average AECO natural gas price (Cdn$/Mcf)	**8.80**	10.00
Average light/heavy oil price differential (Cdn$/bbl)	**30.00**	28.00
Average exchange rate (Cdn$/US$)	**0.86**	0.85
Capital expenditures ($ millions)	**6.0**	6.0
Long-term debt at year end ($ millions)	**100**	94
Weighted average Trust Units outstanding (thousands)	**49,100**	49,086
Payout ratio (%)	**89**	80
Estimated taxability of distributions, as other income (%)	**100**	85

2006 Sensitivity Analysis

		Estimated Change in Distributions to Unitholders	
Variables	Change (+/-)	($000s)	($/Trust Unit)
WTI crude oil price	US$1.00/bbl	2,249	0.05
Light/heavy oil price differential	Cdn$1.00/bbl	1,940	0.04
Natural gas price	Cdn$0.25/Mcf	1,756	0.04
Exchange rate (US$/Cdn$)	0.01	1,319	0.03
Interest rates	1%	1,040	0.02
Oil and NGL production	100 bbls/d	1,461	0.03
Natural gas production	1,000 Mcf/d	3,143	0.06

FOR FURTHER INFORMATION, PLEASE CONTACT:

David Sandmeyer, President & CEO (403) 221-0848
Joe Holowisky, Vice-President, Finance & CFO (403) 221-0855
Karen Taylor, Manager, Investor Relations (403) 221-0891

Freehold Royalty Trust
Phone: (403) 221-0802
Fax: (403) 221-0888
(toll free in Canada/U.S. 1-888-257-1873)
E-mail: ir@freeholdtrust.com
Website: www.freeholdtrust.com

Consolidated Balance Sheets

($000s) (Unaudited)	**December 31, 2005**	December 31, 2004
Assets		
Current assets:		
Cash	**$ 192**	$ 66
Accounts receivable	**35,728**	12,797
	35,920	12,863
Reclamation fund	**1,964**	1,646
Petroleum and natural gas interests, net of accumulated depletion and depreciation of $237,857 (2004 - $180,919)	**496,194**	193,492
	$ 534,078	$ 208,001
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders (note 7)	**$ 12,748**	$ 3,785
Accounts payable and accrued liabilities	**6,891**	4,950
	19,639	8,735
Asset retirement obligation (note 5)	**4,036**	3,937
Long-term debt (note 3)	**107,000**	27,000
Future income tax liability	**3,932**	3,507
Unitholders' equity:		
Unitholders' capital (note 4)	**560,049**	298,936
Deficit	**(160,578)**	(134,114)
	399,471	164,822
	$ 534,078	$ 208,001

Consolidated Statements of Income and Deficit

(Unaudited) ($000s, except per unit and weighted average data)	Three Months Ended December 31 **2005**	 2004	Year Ended December 31 **2005**	 2004
Revenue:				
Royalty income and working interest sales	**$ 44,555**	$ 19,936	**$ 136,914**	$ 78,491
Royalty expense (net of Alberta Royalty Tax Credit)	**(1,191)**	(732)	**(3,591)**	(2,977)
	43,364	19,204	**133,323**	75,514
Expenses:				
Operating	**1,912**	1,423	**6,530**	5,860
General and administrative	**1,222**	864	**4,392**	3,502
Interest on long-term debt	**1,141**	172	**3,158**	635
Depletion and depreciation	**18,820**	6,522	**56,938**	25,661
Accretion of asset retirement obligation	**67**	60	**252**	232
Management fee	**670**	393	**2,178**	1,428
	23,832	9,434	**73,448**	37,318
Net income before taxes	**19,532**	9,770	**59,875**	38,196
Income and capital taxes	**361**	592	**1,105**	1,147
Future income tax provision	**424**	(219)	**424**	157
	785	373	**1,529**	1,304
Net income	**$ 18,747**	$ 9,397	**$ 58,346**	$ 36,892
Deficit, beginning of period	**(147,959)**	(128,062)	**(134,114)**	(116,516)
Distributions declared	**(31,366)**	(15,449)	**(84,810)**	(54,490)
Deficit, end of period	**$ (160,578)**	$ (134,114)	**$ (160,578)**	$ (134,114)
Net income per Trust Unit, basic and diluted	**$ 0.38**	$ 0.30	**$ 1.36**	$ 1.17
Weighted average number of Trust Units	**48,996,315**	31,521,981	**42,812,470**	31,488,355

Consolidated Statements of Cash Flows

(Unaudited) ($000s)	Three Months Ended December 31 **2005**	2004	Year Ended December 31 **2005**	2004
Cash provided by (used in):				
Operating:				
Net income	$ **18,747**	$ 9,397	$ **58,346**	$ 36,892
Items not involving cash:				
Depletion and depreciation	**18,820**	6,522	**56,938**	25,661
Future income tax provision	**424**	(219)	**424**	157
Accretion of asset retirement obligation	**67**	60	**252**	232
Trust Units issued in lieu of management fee	**670**	393	**2,178**	1,428
Expenditures on reclamation	**(34)**	(14)	**(104)**	(57)
Funds generated from operations	**38,694**	16,139	**118,034**	64,313
Changes in non-cash working capital	**567**	1,547	**(20,967)**	(262)
	39,261	17,686	**97,067**	64,051
Financing:				
Issue of Trust Units, net of issue costs	—	—	**258,935**	—
Long-term debt	**(11,000)**	10,000	**80,000**	9,000
Distributions paid	**(25,477)**	(15,447)	**(75,848)**	(53,851)
Changes in non-cash working capital	**22**	(14)	**(142)**	(8)
	(36,455)	(5,461)	**262,945**	(44,859)
Investing:				
Corporate acquisition	—	—	—	(3,048)
Property and royalty acquisitions	—	(9,799)	**(351,705)**	(10,013)
Development expenditures	**(1,631)**	(1,895)	**(7,982)**	(5,823)
Increase in reclamation fund	**(72)**	(90)	**(318)**	(357)
Changes in non-cash working capital	**(928)**	(458)	**119**	58
	(2,631)	(12,242)	**(359,886)**	(19,183)
Increase (decrease) in cash	**175**	(17)	**126**	9
Cash, beginning of period	**17**	83	**66**	57
Cash, end of period	$ **192**	$ 66	$ **192**	$ 66

Notes to Interim Consolidated Financial Statements

For the period ended December 31, 2005.

These interim consolidated financial statements and notes have not been reviewed or audited by external auditors.

1. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Freehold Royalty Trust (“Freehold”) have been prepared by management in accordance with Canadian generally accepted 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 which 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 million extendible revolving term credit facility, extendible annually, on which $107 million was drawn at December 31, 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 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 million demand debentures over Freehold’s petroleum and natural gas assets.

4. UNITHOLDERS' CAPITAL

	December 31, 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	**123,825**	**2,178**	90,000	1,428
Balance, end of period	**49,031,581**	**560,049**	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 $4.0 million (discounted at a weighted average credit adjusted risk free rate of 6.2%), with the undiscounted value being $10.3 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.

($000s)	**December 31, 2005**	December 31, 2004
Balance, beginning of period	**3,937**	3,606
Liabilities incurred	**210**	156
Liabilities added upon acquisition	**19**	—
Liabilities settled	**(104)**	(57)
Liabilities disposed	**(352)**	—
Revisions in estimates (1)	**74**	—
Accretion expense	**252**	232
Balance, end of period	**4,036**	3,937

(1) Revisions in estimates are mainly a result of changes provided by the Trust's independent reserves evaluator.

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 year ended December 31, 2005 was 123,825 Trust Units.

For the year ended December 31, 2005, the Manager charged the Trust $3.0 million in general and administrative costs. At December 31, 2005 there was $219,000 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 $5.3 million for the year ended December 31, 2005, which was included as a cost of acquiring Petrovera Resources.

7. DISTRIBUTIONS TO UNITHOLDERS

As a result of excess taxable income earned in 2005, the Trust declared an additional distribution of $0.08 per Trust Unit on February 9, 2006. This amount is reflected as a current liability in Distributions payable to Unitholders, along with the Trust's regular $0.18 per Trust Unit distribution.

8. SUPPLEMENTAL CASH FLOW DISCLOSURE

CASH EXPENSES PAID	**Three months Ended December 31**		Year Ended December 31	
($000s)	**2005**	**2004**	2005	2004
Interest	**1,118**	**185**	3,301	643
Taxes	**247**	**155**	1,465	808

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

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

2005 FOURTH QUARTER DISTRIBUTIONS (1)

Record Date	Payment Date	Per Trust Unit
October 31, 2005	November 15, 2005	$0.14
November 30, 2005	December 15, 2005	$0.24 (2)
December 31, 2005	January 15, 2006	$0.18
February 20, 2006	March 15, 2006	$0.08 (3)
		$0.64

(1) For Canadian residents, 100% of 2005 distributions to Unitholders are taxable as other income. Tax information and historical distributions are available on our website at www.freeholdtrust.com.

(2) Includes $0.06 top-up related to the third quarter.

(3) Special distribution paid in 2006 as a result of excess taxable income earned in 2005.

HEAD OFFICE

Freehold Resources Ltd.
Freehold Royalty Trust
400, 144 - 4th Avenue S.W.
Calgary, Alberta T2P 3N4
Telephone: (403) 221-0802
Fax: (403) 221-0888

INVESTOR RELATIONS

Karen C. Taylor
Manager, Investor Relations
Direct: (403) 221-0891
Fax: (403) 221-0888
Toll Free: 1-888-257-1873
Email: ir@freeholdtrust.com

WEBSITE

www.freeholdtrust.com

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading Symbol: FRU.UN

2005 FOURTH QUARTER TRADING SUMMARY

High – $18.98
Low – $15.15
Close – $18.81
Volume – 7,611,190
Trust Units Outstanding – 49.0 million
Dec. 31 Market Capitalization – $922 million

TRUSTEE & TRANSFER AGENT

Computershare Trust Company of Canada
600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Toll Free: 1-888-267-6555
Fax: (403) 267-6598
Email: service@computershare.com

LEGAL COUNSEL

Burnet Duckworth & Palmer, LLP
Calgary, Alberta

AUDITORS

KPMG, LLP
Calgary, Alberta

BANKER

Canadian Imperial Bank of Commerce
Calgary, Alberta

EVALUATION ENGINEERS

Trimble Engineering Associates Ltd.
Calgary, Alberta