

Freehold

ROYALTY TRUST

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NEWS RELEASE

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Freehold Royalty Trust Announces 2009 Fourth Quarter Results and Year End Reserves

CALGARY, ALBERTA, (Marketwire – March 3, 2010) – Freehold Royalty Trust (Freehold or the Trust) (TSX:FRU.UN) today announced fourth quarter results and full year results for the period ended December 31, 2009.

RESULTS AT A GLANCE Financial (\$000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	Change	2009	2008	Change
Gross revenue	35,167	34,461	2%	119,965	204,116	-41%
Net income	14,721	13,374	10%	31,741	109,956	-71%
Per Trust Unit, basic and diluted (\$)	0.29	0.27	6%	0.63	2.23	-72%
Cash provided by operating activities	25,937	41,672	-38%	95,659	179,252	-47%
Per Trust Unit (\$)	0.50	0.84	-40%	1.91	3.63	-47%
Funds generated from operations (1)	30,444	26,942	13%	95,085	171,282	-44%
Per Trust Unit (\$)	0.59	0.55	7%	1.90	3.47	-45%
Capital expenditures	4,435	3,770	18%	15,491	12,992	19%
Property and royalty acquisitions (net)	9,539	(782)	1320%	9,539	7,693	24%
Distributions declared	23,937	54,387	-56%	70,480	143,749	-51%
Per Trust Unit (\$) (2)	0.46	1.10	-58%	1.40	2.91	-52%
Long-term debt, period end	45,000	140,000	-68%	45,000	140,000	-68%
Unitholders' equity, period end	298,972	220,005	36%	298,972	220,005	36%
Trust Units (000s) (3)	51,483	49,424	4%	50,000	49,371	1%
Operating						
Average daily production (boe/d) (4)	7,402	7,779	-5%	7,302	7,804	-6%
Average price realizations (\$/boe) (4)	51.09	46.55	10%	44.00	69.93	-37%
Operating netback (\$/boe) (1) (4) (5)	45.66	42.14	8%	39.61	65.18	-39%

(1) See non-GAAP measures.

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

(3) Weighted average number of Trust Units outstanding during the period, basic.

(4) See "Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".

(5) Excludes other income.

DISTRIBUTION

The Board of Directors has declared the March distribution of \$0.14 per Trust Unit which will be paid on April 15, 2010 to Unitholders of record on March 31, 2010 (ex-distribution date March 29, 2010). Including the April 15 payment, our 12-month trailing cash distributions total \$1.52 per Trust Unit. The regular monthly distribution will remain fixed at \$0.14 per Trust Unit until further notice.

FOURTH QUARTER HIGHLIGHTS

Our results for the fourth quarter reflect improved oil prices which, together with our oil-weighted product mix and the low cost structure of our royalty production, combined to deliver strong netbacks. Fourth quarter production volumes were down 5%, mainly due to a lack of drilling activity on our royalty lands during 2009.

In December, we improved our already strong balance sheet with an equity offering, issuing 7.6 million Trust Units at \$15.15 per Trust Unit. This was only our third equity offering in 13 years, and we were pleased by the market's response and by the confidence demonstrated not only by the participation of our largest Unitholder, CN Pension Trust Funds, but also by the underwriters' exercise of the full 15% over-allotment option. Net proceeds of \$110.5 million were used, initially, to reduce long-term debt and, subsequently to fund \$49 million in royalty acquisitions.

CRUDE OIL AND NATURAL GAS MARKETS

Overall, the outlook for crude oil is more favourable than for natural gas. Markets for heavy oil remain robust due to strong refinery demand for this product type. Winter weather has increased heating demand throughout North America, and natural gas markets have responded with modest price increases. Although these factors are positive in the short-term, we believe that the road to full economic recovery will be long and bumpy, with continued commodity price volatility. The commodity price fluctuations of the past 18 months serve to reinforce that our cash flows, and thus our distributions, are largely dependant on cyclical supply and demand factors that are beyond our control.

ROYALTY LANDS AND INDUSTRY ACTIVITY

Industry activity levels in the final three months of the year remained muted compared to 2008 with fewer than 1,800 wells drilled in western Canada. Industry drilled 55% fewer wells overall in 2009 than in 2008, and the average utilization rate for Canadian drilling rigs was at an all time low of 26%. As expected, drilling on our royalty lands in 2009 reflected the overall decline in industry activity levels; however, at year-end, there were 86 licensed drilling locations on our royalty lands, up from 64 locations at the end of 2008.

The Petroleum Services Association of Canada recently updated its 2010 Canadian drilling activity forecast and is "cautiously optimistic" that commodity prices will strengthen further in 2010, leading to increased drilling activity. The Alberta Government's short-term stimulus plan to encourage conventional oil and natural gas activity in the province is also expected to have a positive impact on industry activity levels in the coming months. While operators may focus on opportunities on Crown lands to take advantage of the incentives, we anticipate that increased activity will be eventually reflected on our royalty lands.

ROYALTY ACQUISITIONS

On December 21, 2009, we completed a royalty acquisition for \$10 million after closing adjustments, expanding our presence in the multi-zone prospective deep basin region of Northwest Alberta. We acquired royalty interests on 43,214 gross acres, of which 26,400 are located in the Bigstone area of Northwest Alberta and represent the creation of a 5% overriding royalty interest. The agreement provides for a drilling contribution by Freehold of up to \$1.9 million over the next five years to assist the vendor in the development of undeveloped lands in the Bigstone area. Future opportunities on the Bigstone lands include natural gas and shallow Cardium oil. The remaining lands (16,814 gross acres) represent the assignment to Freehold of gross overriding royalties of varying percentages of production in 12 properties in Alberta and British Columbia. Current production consists of primarily liquids rich, sweet natural gas from 15 gross wells. Reserves were independently evaluated at 0.3 MMboe net proved plus probable, effective December 31, 2009, and have an estimated reserve life index of six years based on annualized 2010 production of 145 boe per day.

Subsequent to year-end, we acquired royalty interests on 319,681 gross acres in Alberta, Saskatchewan, and British Columbia, for \$39 million, after closing adjustments. The acquisition represents the creation of a 5% overriding royalty interest on 11 producing properties and the assignment to Freehold of eight small gross overriding royalty interests. Current production is 60% natural gas from 600 gross wells. Reserves were independently evaluated at 1.4 MMboe net proved plus probable, and have an estimated reserve life index of just under nine years. These reserves are not included in our December 31, 2009 reserve update. The acquisition closed on February 17, 2010 and is expected to add 380 boe per day to 2010 production. We anticipate further development on these lands over the next several years.

Both acquisitions support our strategy of focusing on oil and gas royalties and are accretive, on a debt-adjusted per unit basis, to cash flow, production, reserves, and net asset value. The creation of overriding royalties provides benefits to both parties. For the vendors, the sale proceeds provide a source of capital to fund their ongoing development activities. For Freehold, the acquired royalty interests bring strong netbacks, as production is unencumbered by operating and capital costs and third party royalty expenses. The acquisitions also allow us to benefit from future development on the properties.

WORKING INTEREST PROPERTIES

In the fourth quarter of 2009, we participated in the drilling of three (1.2 net) Bakken wells. One (0.5 net) well was a stratigraphic test and considered dry and abandoned; the other two (0.7 net) wells came on production in December. Since 2005, we have participated in the drilling of 28 (7.7 net) Bakken wells on our lands.

Our first two 100% wells on our Bakken oil-prone lands in Southeast Saskatchewan, drilled in the third quarter of 2009, commenced production in November, and each averaged 80 barrels per day in December.

2010 PLANS

On our working interest properties, we anticipate spending approximately \$24 million in 2010. This represents a substantial increase over 2009, as we plan to accelerate development of our Bakken-prone title lands in Southeast Saskatchewan. In addition, we anticipate an active program at Pembina Cardium Unit #9 as the operator, Penn West, continues with field redevelopment using horizontal infill drilling and multi-stage fracture stimulation. With additional production from our recent acquisitions and a larger capital program, we are forecasting average production of 7,600 boe per day for 2010; royalty interests are expected to account for 70% of this production. General and administrative costs will be higher than last year as a result of consulting fees related to our IFRS conversion project and evaluation of the impact of the SIFT tax. DRIP proceeds of approximately \$24 million will be used to reduce debt and fund a portion of our capital program. As we are now issuing DRIP units from treasury, the weighted average number of Trust Units outstanding is expected to be 58.4 million.

2010 KEY OPERATING ASSUMPTIONS	March 3 2010	Nov. 10 2009
Average daily production (boe/d)	7,600	7,000
Average WTI oil price (US\$/bbl)	80.00	75.00
Average AECO natural gas price (Cdn\$/Mcf)	5.00	5.00
Average exchange rate (Cdn\$/US\$)	0.96	0.90
Average operating costs (\$/boe)	4.30	4.75
Average G&A costs (\$/boe) (1)	3.20	3.00
Capital expenditures (\$ millions)	24.0	24.0
Proceeds from DRIP (\$ millions) (2)	24.0	-
Long-term debt at year end (\$ millions)	53.7	125.0
Weighted average Trust Units outstanding (thousands)	58,363	50,734
Estimated portion of distributions taxable as income (%)	90-100%	90-100%

(1) Excludes unit based and other compensation.

(2) Assumes a 24% participation rate in 2010.

Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including light/heavy oil price differentials), foreign exchange rates, or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as roughly one third of our total boe production is heavy oil.

A sensitivity analysis of the potential impact of key variables on distributions to Unitholders is provided below.

Variables	Change (+/-)	Estimated Change in Distributions to Unitholders	
		(\$000s)	(\$/Trust Unit)
WTI crude oil price	US\$1.00/bbl	1,860	0.03
Light/heavy oil price differential	Cdn\$1.00/bbl	1,753	0.03
Natural gas price	Cdn\$0.25/Mcf	1,530	0.03
Exchange rate (US\$/Cdn\$)	0.01	1,408	0.02
Interest rates	1%	500	0.01
Oil and NGL production	100 bbls/d	2,605	0.04
Natural gas production	1,000 Mcf/d	1,765	0.03

SIFT TAX STRATEGY UPDATE

We have always maintained that Freehold, with its large, diversified asset base of primarily royalty interests, low risk profile, low sustaining capital requirements, and high payout ratio, is ideally suited to the income trust structure. However, with the new tax on income trusts beginning in 2011, we are evaluating alternative structures. Last year, our Board established a special committee of independent directors and charged them with a mandate to determine a course of action that best maximizes Unitholder value. While a clear direction has not yet been determined, the committee has been examining the structures that our peers are adopting, assessing overall market sentiment, and considering complex legal and tax issues, including implications with respect to future access to capital.

The assets we acquired with the \$264 million proceeds of our Initial Public Offering in November 1996 have performed very well over the past 13 years, supported by an experienced management team who have managed those assets for more than a quarter century. We have augmented our holdings over the years with complementary acquisitions, resulting in an overall asset value of \$13.06 per Trust Unit at December 31, 2009. During this period, we declared distributions of \$20.53 per Trust Unit, more than double the IPO price of \$10.00.

MANAGEMENT

In our third quarter report, we announced that Michael Okrusko, will retire at the end of this year, after serving for more than 28 years with Rife Resources, the Manager of the Trust. To facilitate succession planning, the Board is pleased to announce the appointment of Michael Okrusko as Senior Vice-President, Special Projects, and the appointment of Michael Stone as Vice-President, Land, effective March 1, 2010.

LAND AND RESERVES UPDATE

At December 31, 2009, our land holdings encompassed just under 2.4 million gross acres, over 90% of which are royalty interests. Proved plus probable reserves totalled 24.1 million barrels of oil equivalent (MMboe), with reserves assigned to 22,929 wells. Royalty interest reserves declined 7.3% year-over-year, while working interest reserves increased 2.4%.

In 2009, we spent \$25.0 million on development activities and acquisitions, adding 1.4 MMboe of net proved plus probable reserves. We replaced approximately 50% of 2009 production at an all-in finding, development and acquisition (FD&A) cost of \$18.86 per boe (including changes in future development capital). These activities resulted in a one-year recycle ratio of 2.1 times the capital invested, and a three-year average recycle ratio of 1.9 times.

On a boe basis, our reserves profile was 38% natural gas, 34% heavy oil, 23% light and medium oil, and 5% natural gas liquids (NGL). Approximately 63% of our reserves are in the proved category, and 99% of our proved reserves are producing, which is high by industry standards. Our reserve life index (RLI) for proved plus probable reserves at the end of 2009 was 9.7 years, compared with 9.8 years at the end of 2008.

Based on the independent evaluation of our reserves as at December 31, 2009, the present value of our net proved plus probable oil and gas reserves (discounted at 10%, before tax), was \$707.6 million, down slightly from \$730.7 million at the end of 2008. Our undeveloped land was independently valued at \$79.4 million, down from \$94.0 million at year-end 2008, due to lower average land sale prices during 2009. Our net asset value was \$13.06 per Trust Unit, compared with \$13.92 per Trust Unit at year-end 2008.

Our oil and natural gas reserves were independently evaluated by Trimble Engineering Associates Ltd. (Trimble) as at December 31, 2009. The evaluation was conducted in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in National Instrument 51-101 (NI 51-101).

Our Reserves Committee met with Trimble to review the findings and procedures, and the reserves report has been accepted by our Board. A summary of net reserves, on a before-tax basis, is provided below. Complete NI 51-101 reserves disclosure, including after-tax reserve values, reserves by major property, and abandonment costs, are included in our annual information form (AIF), which will be filed on SEDAR later this month.

The reserves data below is presented on a net basis (our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands). Freehold is unique in that the majority of our assets are royalty interests. However, under NI 51-101, royalty interests cannot be included under gross reserves. This causes our gross reserves to be lower than our net reserves and makes it difficult for investors to compare our reserves to others in our industry. We believe the most appropriate measure of reserves for Freehold is net reserves.

OIL AND GAS RESERVES AS AT DECEMBER 31, 2009 ⁽¹⁾	Light and Medium Crude Oil		Heavy Crude Oil		Total Crude Oil	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)
Reserves Category						
Proved developed producing	1,673	3,520	1,042	4,806	2,715	8,326
Proved developed non-producing	88	77	-	-	88	77
Proved undeveloped	-	-	-	83	-	83
Total proved	1,761	3,596	1,042	4,889	2,803	8,485
Probable	1,000	1,974	717	3,270	1,717	5,244
Total proved plus probable	2,761	5,571	1,759	8,159	4,520	13,730

Reserves Category	Natural Gas		Natural Gas Liquids		Oil Equivalent ⁽⁴⁾	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
	(MMcf)	(MMcf)	(Mbbbl)	(Mbbbl)	(Mboe)	(Mboe)
Proved developed producing	4,782	35,428	179	824	3,690	15,055
Proved developed non-producing	15	15	-	-	90	79
Proved undeveloped	-	113	-	-	-	102
Total proved	4,796	35,555	179	824	3,780	15,236
Probable	2,889	19,060	89	398	2,287	8,818
Total proved plus probable	7,685	54,615	268	1,222	6,068	24,054

(1) Numbers may not add due to rounding.

(2) Gross reserves are our share of working interest properties before deduction of royalties payable to others. Gross reserves exclude royalty interests.

(3) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands.

(4) See "Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".

RECONCILIATION OF NET OIL AND GAS RESERVES BY PRINCIPAL PRODUCT TYPE ^{(1) (2)}	Light and	Heavy	Total	Natural	Associated	Oil
	Medium Crude Oil (Mbbbls)	Crude Oil (Mbbbls)	Crude Oil (Mbbbls)	Gas Liquids (Mbbbls)	and Non- Associated Gas (MMcf)	Equivalent ⁽⁴⁾ (Mboe)
Proved Producing						
December 31, 2008	3,839	5,311	9,150	815	38,132	16,321
Extensions	203	266	469	17	732	608
Improved recovery	-	-	-	-	-	-
Technical revisions	18	216	234	117	1,822	655
Discoveries	-	-	-	-	-	-
Acquisitions	7	5	12	21	1,065	211
Dispositions	-	-	-	-	-	-
Economic factors	(10)	(7)	(17)	-	93	(2)
Production ⁽³⁾	(537)	(985)	(1,522)	(146)	(6,415)	(2,737)
December 31, 2009	3,520	4,806	8,326	824	35,428	15,055
Total Proved						
December 31, 2008	3,891	5,424	9,315	816	38,253	16,506
Extensions	211	266	477	17	732	615
Improved recovery	-	-	-	-	-	-
Technical revisions	35	186	221	116	1,825	642
Discoveries	-	-	-	-	-	-
Acquisitions	7	5	12	21	1,068	211
Dispositions	-	-	-	-	-	-
Economic factors	(10)	(7)	(17)	-	93	(2)
Production ⁽³⁾	(537)	(985)	(1,522)	(146)	(6,415)	(2,737)
December 31, 2009	3,596	4,889	8,486	824	35,555	15,236
Proved Plus Probable						
December 31, 2008	5,862	8,584	14,446	1,203	58,348	25,374
Extensions	427	449	876	30	1,193	1,106
Improved recovery	-	-	-	-	-	-
Technical revisions	(180)	113	(67)	101	(322)	(19)
Discoveries	-	-	-	-	-	-
Acquisitions	10	8	18	34	1,640	325
Dispositions	-	-	-	-	-	-
Economic factors	(11)	(10)	(21)	-	171	7
Production ⁽³⁾	(537)	(985)	(1,522)	(146)	(6,415)	(2,737)
December 31, 2009	5,571	8,159	13,730	1,222	54,615	24,054

(1) Numbers may not add due to rounding.

(2) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands.

(3) Production estimated by Trimble.

(4) See "Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".

RESERVE LIFE INDEX ⁽¹⁾	Proved	Total	Proved Plus
	Producing	Proved	Probable
Net reserves (Mboe)	15,055	15,236	24,054
Net production (Mboe)	2,254	2,263	2,486
Reserve life index (years)	6.7	6.7	9.7

(1) Calculated by dividing the Trimble forecast of 2010 net production into the remaining net reserves.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS AT DECEMBER 31, 2009 - FORECAST PRICES AND COSTS ^{(1) (2)}

(\$000s)	Proved	Proved Plus Probable
Royalty Income	800,067	1,386,532
Revenue from Working Interest Properties	346,386	593,629
Royalty expense on Working Interest Properties	(40,697)	(74,516)
Operating costs	(122,912)	(205,156)
Development costs	(878)	(5,650)
Well abandonment and reclamation costs	(7,356)	(8,710)
Future net revenue before income taxes	974,611	1,686,129
Future income taxes	(172,862)	(351,604)
Future net revenue after income taxes	801,749	1,334,525

(1) Future net revenue values do not represent fair market value.

(2) Future net revenue calculation includes future capital expenditures required to bring booked non-producing and undeveloped reserves on production.

FUTURE DEVELOPMENT COSTS ⁽¹⁾

(\$000s)	Proved Reserves	Proved Plus Probable Reserves
2010	92	2,392
2011	558	2,816
2012	73	73
2013	30	30
2014	30	30
Remainder	95	309
Total	878	5,650

(1) Based on forecast prices and costs. The source of funding for future development costs includes internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures.

NET PRESENT VALUES OF FUTURE NET REVENUE ^{(1) (2) (3)}

(\$000s)	Before tax, discounted at			
	0% per year	5% per year	10% per year	15% per year
Proved developed producing	966,459	663,285	513,341	424,571
Proved developed non-producing	1,803	1,033	688	506
Proved undeveloped	6,349	4,828	3,831	3,142
Total proved	974,611	669,146	517,860	428,218
Total probable	711,518	316,540	189,723	133,147
Proved plus probable	1,686,129	985,686	707,583	561,366

(1) Columns may not add due to rounding.

(2) Forecast prices and costs, before tax, based on the December 31, 2009 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

(3) Future net revenue values do not represent fair market value.

ANALYSIS OF FINDING, DEVELOPMENT AND ACQUISITIONS (FD&A) COSTS ^{(1) (2) (3) (4)}	2009	2008	2007	Three-Year Results
Net Proved Reserves:				
Development expenditures (\$000s)	15,491	12,992	12,167	40,650
Change in future development capital estimates (\$000s)	(295)	597	(2,376)	(2,074)
Net reserve additions by development (Mboe)	615	409	329	1,353
Development costs (\$/boe)	24.70	33.22	29.79	28.51
Acquisition expenditures (\$000s)	9,539	7,693	90,456	107,688
Net reserve additions by acquisition (Mboe)	211	192	1,696	2,100
Acquisition costs (\$/boe)	45.14	40.07	53.33	51.29
Total expenditures (\$000s)	25,030	20,685	102,623	148,338
Change in future development capital estimates (\$000s)	(295)	597	(2,376)	(2,074)
Net reserve additions (Mboe)	827	601	2,025	3,453
Development and acquisition costs (\$/boe)	29.92	35.41	49.50	42.36
Net Proved Plus Probable Reserves:				
Development expenditures (\$000s)	15,491	12,992	12,167	40,650
Change in future development capital estimates (\$000s)	1,944	(564)	(3,305)	(1,925)
Net reserve additions by development (Mboe)	1,106	833	616	2,555
Development costs (\$/boe)	15.77	14.92	14.38	15.16
Acquisition expenditures (\$000s)	9,539	7,693	90,456	107,688
Net reserve additions by acquisition (Mboe)	325	272	2,473	3,070
Acquisition costs (\$/boe)	29.38	28.25	36.57	35.07
Total expenditures (\$000s)	25,030	20,685	102,623	148,338
Change in future development capital estimates (\$000s)	1,944	(564)	(3,305)	(1,925)
Net reserve additions (Mboe)	1,430	1,105	3,090	5,625
Development and acquisition costs (\$/boe)	18.86	18.20	32.15	26.03

(1) The Trust did not incur any exploration costs in any of the applicable years.

(2) In calculating finding and development costs, NI 51-101 requires that the exploration and development costs incurred in the year and the change in estimated future development costs be aggregated and then divided by the applicable reserve additions. The calculation specifically excludes the effects of acquisitions on both reserves and costs. We believe that by excluding the effects of acquisitions the provisions of NI 51-101 do not fully reflect the Trust's ongoing reserve replacement costs. Because acquisitions can have a significant impact on the Trust's annual reserve replacement costs, excluding these amounts could result in an inaccurate portrayal of the Trust's cost structure. Accordingly, we also provide costs that incorporate all acquisitions during the year.

(3) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(4) See "Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".

RECYCLE STATISTICS

NET PROVED PLUS PROBABLE RESERVES

(\$ per boe, except as noted) ⁽¹⁾	2009	2008	2007	Three-Year Results
Operating netback ^{(2) (5)}	39.61	65.18	43.54	49.50
Development and acquisition costs ^{(3) (5)}	18.86	18.20	32.15	26.03
Recycle ratio (times) ⁽⁴⁾	2.1	3.6	1.4	1.9

(1) See "Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".

(2) Total revenue, less operating costs and royalty expenses.

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

(4) Operating netback divided by the average cost of acquiring and developing new reserves.

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

SUMMARY OF LAND HOLDINGS (gross acres) (1)	Total Land Holdings		Undeveloped Land	
	2009	2008	2009	2008
Mineral title lands (2)	548,198	549,925	160,232	162,972
Gross overriding royalty (GORR) lands (3)	1,530,160	1,518,423	425,760	423,188
Royalty assumption lands (4)	95,111	95,592	18,925	19,962
Total royalty lands	2,173,469	2,163,940	604,917	606,122
Working interest properties	212,413	210,606	43,445	44,998
Total land holdings	2,385,882	2,374,546	648,362	651,120

LAND HOLDINGS BY PROVINCE (gross acres) (1)	As at December 31		
	2009	2008	2007
Alberta	1,493,335	1,485,388	1,488,098
Saskatchewan	507,707	503,634	505,223
Ontario	295,769	295,769	296,109
British Columbia	80,788	81,472	82,423
Manitoba	8,283	8,283	8,283
Total	2,385,882	2,374,546	2,380,136

- (1) Gross acres represents the total number of acres in which we have an interest.
- (2) The royalties received from the sale of oil, natural gas and potash produced from the leased mineral title lands are determined by the individual lease agreements. Mineral title lands are held in perpetuity. All but 100,546 gross acres of our mineral title lands are currently leased to third parties.
- (3) Gross overriding royalty lands consist of properties owned by a number of third party oil and gas companies in respect of which varying royalties or net profits interests have been reserved to Freehold.
- (4) Mineral title properties owned by a number of third party oil and gas companies in respect of which gross overriding royalties varying from 4.7% to 6.5% have been reserved to Freehold.

NET ASSET VALUE AS AT DECEMBER 31, 2009 (1) (2)

(\$000s, except unit data)	2009	2008	2007
Present value of oil and gas reserves (3) (7)	707,583	730,659	711,624
Present value of potash reserves (4) (7)	17,809	27,807	14,317
Undeveloped land (5)	79,408	93,975	30,252
Reclamation fund (6)	2,261	1,827	1,788
Working capital (6)	(3,082)	(20,055)	11,219
Bank debt (6)	(45,000)	(140,000)	(178,000)
Asset retirement obligations (6)	(7,160)	(5,663)	(6,608)
Net asset value	751,818	688,550	584,592
Trust Units outstanding (000s)	57,503	49,459	49,317
Net asset value per Trust Unit (\$)	13.06	13.92	11.85

- (1) Non-GAAP measure. Net asset value (NAV) is a measure used widely within the investment community and in the oil and natural gas industry. It shows what is normally referred to as a 'produce-out' NAV calculation under which the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It does not represent a 'going concern' value and it should not be assumed that the present value of oil and gas reserves represent the fair market value of the reserves. Net asset value does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.
- (2) Columns may not add due to rounding.
- (3) Based on net proved plus probable reserves evaluated by Trimble, before tax, discounted at 10%, and includes future capital expenditure expectations required to bring undeveloped reserves on production.
- (4) Based on net proved plus probable reserves evaluated internally, before tax, discounted at 10%. Potash reserves are not subject to NI 51-101.
- (5) Evaluated by Seaton-Jordan & Associates Ltd.
- (6) Financial information per Freehold's consolidated financial statements.
- (7) Future net revenue values do not represent fair market value.

As noted above, subsequent to year-end we acquired additional royalty interests, adding approximately 319,700 gross acres of land, 1.4 MMboe of net proved plus probable reserves, and 435 boe per day of production for 2010. This acquisition is not included in reserves, land and net asset value as at December 31, 2009.

AVAILABILITY ON SEDAR

Freehold's 2009 fourth quarter report, including unaudited financial statements and Management's Discussion and Analysis, is being filed today with Canadian securities regulators and will be available on SEDAR at www.sedar.com or on our website.

FORWARD-LOOKING STATEMENTS

This news release offers our assessment of Freehold's future plans and operations as at March 3, 2010, and contains forward-looking statements including our expectations for improving economic conditions, industry drilling and activity on our royalty lands and the benefits therefrom, capital expenditures, average production, commodity prices including our outlook for crude oil and natural gas, demand for heavier crude, and acquisition opportunities. These forward-looking statements are provided to allow readers to better understand our business and prospects.

Such statements are generally identified by the use of words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "plan", "intend", "believe", and similar expressions (including the negatives thereof). 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, taxation, royalties, regulation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. Risks are described in more detail in our AIF.

With respect to forward-looking statements contained in this news release, we have made assumptions regarding, among other things, future oil and natural gas prices, future capital expenditure levels, future production levels, future exchange rates, future participation rates in the DRIP, the cost of developing and producing our assets, our ability and the ability of our lessees to obtain equipment in a timely manner to carry out development activities, our ability to market our oil and natural gas successfully to current and new customers, our expectation for the consumption of crude oil and natural gas, our expectation for industry drilling levels, our ability to obtain financing on acceptable terms, and our ability to add production and reserves through development and acquisition activities.

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. The forward-looking information contained in this news release is expressly qualified by this cautionary statement. Our policy for updating forward-looking statements is to update our key operating assumptions quarterly and, except as required by law, we do not undertake to update any other forward-looking statements.

CONVERSION OF NATURAL GAS TO BARRELS OF OIL EQUIVALENT (BOE)

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation.

NON-GAAP MEASURES

Within this news release, references are made to terms commonly used as key performance indicators in the oil and gas industry. We believe that operating netback, funds generated from operations, and net debt to funds generated from operations are useful supplemental measures for management and investors to analyze operating performance, financial leverage, and liquidity, and we use these terms to facilitate the understanding and comparability of our results of operations and financial position. However, these terms do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

Operating netback, which is calculated as average unit sales price less royalties and operating expenses, represents the cash margin for product sold, calculated on a per boe basis.

Funds generated from operations is a financial term commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital and is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with GAAP. The key difference between cash provided by operating activities and funds generated from operations is changes in non-cash working capital, which is affected by accounts receivable, accounts payable, and accrued liabilities. Accounts receivable, and therefore working capital, can fluctuate greatly between reporting periods due to timing of receipt of payments. In the event that commodity prices and/or volumes have changed significantly from the previous reporting period, a significant difference could occur between cash provided by operating activities and funds generated from operations. All references to funds generated from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital as per the Statements of Cash Flows. Funds generated from operations per Trust Unit is calculated based on the weighted average number of Trust Units outstanding consistent with the calculation of net income per Trust Unit.

Net debt to funds generated from operations is calculated as net debt (total debt less positive working capital) as a proportion of funds generated from operations for the previous twelve months.

In addition, we refer to various per boe figures, such as revenues and costs, also considered non-GAAP measures, which provide meaningful information on our operational performance. We derive per boe figures by dividing the relevant revenue or cost figure by the total volume of oil and natural gas production during the period, with natural gas converted to equivalent barrels of oil as described above.

FOR FURTHER INFORMATION, PLEASE CONTACT:

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