

# Freehold

ROYALTY TRUST

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## NEWS RELEASE

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### Freehold Royalty Trust Announces 2010 Third Quarter Results

**CALGARY, ALBERTA, (Marketwire – November 10, 2010) – Freehold Royalty Trust** (Freehold or the Trust) (TSX:FRU.UN) today announced third quarter results for the period ended September 30, 2010.

Our results for the third quarter and year to date reflect improved commodity prices compared with last year, along with higher production volumes due to acquisitions completed in December 2009 and February 2010, ongoing development of our royalty lands, and a successful capital program for the year to date.

RESULTS AT A GLANCE	Three Months Ended			Nine Months Ended		
	September 30			September 30		
Financial (\$000s, except as noted)	2010	2009	Change	2010	2009	Change
Gross revenue	32,637	29,016	12%	101,630	84,798	20%
Net income	8,966	7,853	14%	25,854	17,020	52%
Per Trust Unit, basic and diluted (\$)	0.15	0.16	-6%	0.44	0.34	29%
Cash provided by operating activities	26,704	26,215	2%	82,678	69,722	19%
Per Trust Unit (\$)	0.46	0.53	-13%	1.42	1.41	1%
Funds generated from operations (1)	25,811	24,189	7%	78,753	64,641	22%
Per Trust Unit (\$)	0.44	0.49	-10%	1.36	1.31	4%
Capital expenditures	6,003	7,368	-19%	13,390	11,056	21%
Property and royalty acquisitions (net)	(153)	-	-	38,317	-	-
Distributions declared	24,617	16,850	46%	73,318	46,543	58%
Per Trust Unit (\$) (2)	0.42	0.34	24%	1.26	0.94	34%
Long-term debt, period end	70,000	147,000	-52%	70,000	147,000	-52%
Unitholders' equity, period end	272,792	192,103	42%	272,792	192,103	42%
Trust Units (000s) (3)	58,536	49,543	18%	58,119	49,500	17%
<b>Operating</b>						
Average daily production (boe/d) (4)	7,495	6,994	7%	7,494	7,268	3%
Average price realizations (\$/boe) (4)	46.44	44.01	6%	48.72	41.57	17%
Operating netback (\$/boe) (1) (4)	41.56	42.16	-1%	43.89	37.55	17%

(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).

## Commodity Price Update

Freehold continues to benefit from the improvement in oil prices this year. Compared to 2009, the average WTI crude oil price was up 12% for the third quarter and up 36% for the year to date. The Canadian dollar also strengthened this year, up 6% and 13% for the quarter and year to date, respectively. As a result, our Canadian dollar realizations, while up compared to last year, did not receive the full benefit of higher WTI prices. As nearly one-third of our production (on a per boe basis) is heavy oil, our realizations were also negatively affected by a wider light/heavy oil differential in the third quarter. Two separate pipeline disruptions, one in Michigan on July 26 and the other in Illinois on September 9, curtailed access to heavy oil refineries in the U.S. Midwest. As a result, heavy oil production was trapped in western Canada. This logjam served to widen the price gap between Edmonton Par (light) and Western Canada Select (heavy). The differential, which averaged \$8.55 per barrel in the first half of this year, rose to \$11.53 per barrel in the third quarter and soared to nearly \$26.00 per barrel at the end of September. Although both pipelines have now been brought back into service, it will take some time for the supply glut to work its way through the system. With the summer asphalt-paving season now over, the differential is expected to remain wider than normal for the rest of this year. Longer term, we believe markets for heavy oil remain positive due to continued strong refinery demand for this product type.

The short-term outlook for natural gas remains uncertain. AECO natural gas prices have improved compared to last year's record lows. However, supply continues to outstrip demand in North America. Leading into the winter heating season, natural gas storage levels remain above the five-year average. Over the coming months, natural gas prices will depend largely on weather-related demand.

## Royalty Lands and Industry Drilling

There has been a significant shift towards oil drilling in 2010, including light oil resource plays such as the Cardium, Bakken, Lower Shaunavon, and Viking. Natural gas drilling has also shifted, targeting deeper, liquids-rich (NGL) reserves, which improve producer netbacks, and focusing on resource plays such as the Glauconite, Lower Mannville, and Montney. Given our extensive land base of almost 2.4 million gross acres spanning much of the Western Canada Sedimentary Basin, we are well positioned to participate in many of the emerging resource plays, although we have little exposure in the northern areas of the Basin. The most promising opportunities for us are in areas south of the North Saskatchewan River in Alberta and in Southeast Saskatchewan where we own significant mineral title lands.

Horizontal drilling technology is increasingly being used to access tight oil and natural gas reservoirs. More than half of the net wells drilled on our lands in the third quarter were horizontal wells, and 75% of these were oil wells.

As at September 30, 2010, there were 117 (3.2 net) licensed drilling locations on our royalty lands compared with 61 (3.2 net) at this time last year. Continued well licence activity is a positive indicator of future activity on our lands. This outlook is supported by the Canadian Association of Oilwell Drilling Contractors (CAODC), which expects a moderate increase in activity next year, to 11,811 wells. The CAODC's 2011 forecast also suggests that activity levels will increase in the last half of the year but assumes little improvement in natural gas prices.

## Working Interest Activity

In the third quarter of 2010, we drilled six (1.1 net) Dina oil wells at Hayter, Alberta; two (1.6 net) Bakken oil wells in Southeast Saskatchewan; and one (0.7 net) Waseca oil well at Lashburn, Saskatchewan. All but one were drilled using horizontal drilling technology. The two Bakken wells were completed using multi-stage fracture stimulation techniques. These nine wells had little impact on production volumes in the third quarter but will add to our production going forward.

Capital investment in 2010 is expected to total \$20 million, 17% lower than our previous estimate. The operator of Pembina Cardium Unit #9 has completed its capital program for this year, drilling fewer wells than originally budgeted. Our expenditures in the fourth quarter will focus on oil development in Southeast Saskatchewan, with two (1.0 net) Bakken wells planned at Taylorton on our mineral title lands.

## Guidance Update

Our Board has approved a capital budget for 2011 of \$20 million for the continued development of our working interest properties, including our Bakken-prone title lands in Southeast Saskatchewan where we continue to see opportunities. Based on this level of capital investment, anticipated drilling activity on our leased royalty lands, normal production declines, and prior to any potential acquisitions, we expect 2011 production to average approximately 7,100 boe per day. Our production remains unhedged, subject to quarterly review by our Board.

Cash preserved through our distribution reinvestment plan (expected to be approximately \$26 million for 2010 and \$27 million for 2011) enhances our ability to fund our capital program, strengthen our balance sheet, and pursue acquisition opportunities, while also allowing us to pay out a higher percentage of cash flow in the form of distributions or dividends.

The following table summarizes our key operating assumptions for 2010, updated to reflect actual results for the first nine months of the year and our current expectations for the fourth quarter, as well as our key operating assumptions for 2011.

KEY OPERATING ASSUMPTIONS (as at November 10, 2010)	2010	2011
Average daily production (boe/d)	7,600	7,100
Average WTI oil price (US\$/bbl)	77.00	80.00
Average exchange rate (Cdn\$/US\$)	0.96	0.95
Average heavy oil differential (Cdn\$/bbl) (1)	—	(13.00)
Average AECO natural gas price (Cdn\$/Mcf)	3.65	4.25
Average operating costs (\$/boe)	4.30	4.50
Average G&A costs (\$/boe) (2)	3.20	3.40
Capital expenditures (\$ millions)	20.0	20.0
Proceeds from DRIP (\$ millions) (3)	26.0	27.0
Long-term debt at year end (\$ millions)	69.0	52.0
Estimated portion of distributions taxable as income (%)	90-100%	—
Weighted average units/shares outstanding (millions) (4)	58.4	60.0

(1) The difference between the Edmonton Par and Western Canada Select crude oil streams.

(2) Excludes unit based and other compensation.

(3) Average participation rates of 25% in 2010 and 27% in 2011.

(4) Corporate conversion completed as currently contemplated.

## November Distribution Announcement

The Board of Directors has declared the November distribution of \$0.14 per Trust Unit, which will be paid on December 15, 2010 to Unitholders of record on November 30, 2010 (ex-distribution date November 26, 2010). Including the December 15 payment, our 12-month trailing cash distributions total \$1.68 per Trust Unit. The regular monthly distribution will remain fixed at \$0.14 per Trust Unit until further notice.

## Corporate Conversion

As announced on October 12, 2010, we are proceeding with our plans to convert Freehold to a corporation. The conversion will permit Unitholders to exchange their Trust Units for common shares of the new corporation on a non-taxable basis. Subject to receiving all necessary Unitholder, regulatory, stock exchange and court approvals, the conversion will be effective on December 31, 2010.

Freehold's business model will not change as a result of converting to a corporation. The conversion will simplify the underlying structure and remove the capital market uncertainty associated with income trusts. The new corporation, Freehold Royalties Ltd., and its subsidiaries will hold the assets and business operations previously held and operated by the Trust and its subsidiaries. All directors and officers of Freehold, other than Michael J. Okrusko, Senior Vice-President, Special Projects, who intends to retire on December 31, 2010, will continue as the directors and officers of Freehold Royalties Ltd.

Our assets and strategies have delivered excellent returns over the past fourteen years, and our intention is to continue on the same path. The majority of our oil and natural gas production comes from mineral title lands and gross overriding royalties, which have no associated capital or operating costs; thus we have relatively low capital expenditure requirements. The strength of our royalties has allowed us to preserve a high payout ratio historically and should allow us to maintain a high dividend payout going forward.

Freehold had approximately \$215 million in tax pools at December 31, 2009, and we do not expect to pay corporate income tax on income earned in 2011. Our ability to generate additional tax pools, which can be used to shelter taxable income, depends on the level of future capital expenditures and acquisitions. Planned capital expenditures will not generate significant new tax pools, and starting in 2012, the Freehold expects to be taxable at a rate of 15% to 20%.

We currently contemplate that Unitholders of record on December 31, 2010, will receive a final distribution from the Trust on January 17, 2011. This distribution is expected to be made pursuant to the conversion, but will be paid in the normal course if the conversion does not proceed. After conversion, we expect to pay our first dividend on February 15, 2011, to shareholders of record on January 31, 2011.

As a corporation, our dividend policy will be similar to our current distribution policy, subject to the satisfaction of liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Dividends will continue to be paid monthly, with the Board reviewing the dividend policy quarterly. Under our current production, commodity price, and operating assumptions, we initially expect to pay a monthly dividend of \$0.14 per share, which is the same as the distribution per Trust Unit we currently pay as a trust. Actual future dividend levels will depend on the cash flow generated by Freehold's assets, which can vary depending on a number of factors, including commodity prices, production volumes, foreign exchange rates, capital expenditures, participation levels in the DRIP, debt service requirements, corporate tax and costs.

Further details about the conversion will be in the information circular to be mailed to Unitholders on or about November 15, 2010, and a special meeting of Unitholders has been called for December 10, 2010 to vote on the conversion. We also encourage Unitholders to visit the Trust's website at [www.freeholdtrust.com](http://www.freeholdtrust.com) for further information.

#### Availability on SEDAR

Freehold's 2010 third 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](http://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 November 10, 2010, and contains forward-looking statements that we believe allow readers to better understand our business and prospects. Forward-looking statements include our expectations for the following:

- our outlook for commodity prices including supply and demand factors relating to crude oil, heavy oil, and natural gas;
- changing economic conditions;
- industry drilling and development activity on our royalty lands;
- participation in the DRIP and our use of cash preserved through the DRIP;
- estimated capital expenditures and the timing thereof;
- long-term debt at year end;
- average production and contribution from royalty lands;
- key operating assumptions;
- acquisition opportunities;
- future income tax;

- our expected conversion to a corporation, including the proposed structure, the timing relating to the approval and implementation thereof, the expected compensation arrangements with the Manager, the benefits expected therefrom for Freehold and its Unitholders, and the anticipated tax effect on Freehold and its Unitholders;
- the proposed dividend policy of Freehold Royalties Ltd., including the amount of dividend proposed to be paid and our ability to sustain that dividend; and
- our tax pools and the expected tax horizon of Freehold Royalties Ltd.

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, royalties, environmental risks, taxation, regulation, changes in tax or other legislation, 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 tax rates, future participation rates in the DRIP and use of cash preserved through the DRIP, our ability to complete the corporate conversion in the manner and timeframe expected, future legislation, 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. The key operating assumptions with respect to these forward-looking statements are detailed in the table above.

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 document 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 natural gas industry. We believe that operating netback and funds generated from operations are useful supplemental measures for management and investors to analyze operating performance, and we use these terms to facilitate the understanding and comparability of our results of operations. 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 natural 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.

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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