

Freehold Royalty Trust Announces 2010 First Quarter Results and Corporate Conversion Plans

RESULTS AT A GLANCE	Three Months Ended		
	March 31		
Financial (\$000s, except as noted)	2010	2009	Change
Gross revenue	36,569	26,618	37%
Net income	7,674	2,391	221%
Per Trust Unit, basic and diluted (\$)	0.13	0.05	169%
Cash provided by operating activities	27,217	21,569	26%
Per Trust Unit (\$)	0.47	0.44	7%
Funds generated from operations (1)	27,745	18,619	49%
Per Trust Unit (\$)	0.48	0.38	26%
Capital expenditures	2,652	2,027	31%
Property and royalty acquisitions (net)	38,399	-	-
Distributions declared	24,265	14,841	63%
Per Trust Unit (\$) (2)	0.42	0.30	40%
Long-term debt, period end	78,000	160,000	-51%
Unitholders' equity, period end	289,351	208,122	39%
Trust Units (000s) (3)	57,700	49,460	17%
Operating			
Average daily production (boe/d) (4)	7,331	7,522	-3%
Average price realizations (\$/boe) (4)	54.45	37.85	44%
Operating netback (\$/boe) (1) (4)	49.44	33.13	49%

(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 "Management's Discussion and Analysis (MD&A) – Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".

May Distribution Announcement

The Board of Directors has declared the May distribution of \$0.14 per Trust Unit which will be paid on June 15, 2010 to Unitholders of record on May 31, 2010 (ex-distribution date May 27, 2010). Including the June 15 payment, our 12-month trailing cash distributions total \$1.60 per Trust Unit. The regular monthly distribution will remain fixed at \$0.14 per Trust Unit until further notice.

Message to Unitholders

Overall, our results for the first quarter of 2010 reflect improved oil prices, which more than offset a 3% decrease in production volumes. Operating netbacks rose 49%, and cash provided by operating activities and net income were both substantially higher due to higher revenues. Distributions in the first quarter were \$0.42 per Trust Unit, up 40% from the first quarter of last year.

Royalty Acquisition

As previously announced, on February 17, 2010 we acquired royalty interests on approximately 319,700 gross acres in Alberta, Saskatchewan, and British Columbia, for \$39 million. Reserves were independently evaluated at 1.4 MMboe proved plus probable, and have an estimated reserve life index of just under nine years assuming annualized 2010 production of 435 boe per day. The acquisition was financed through our existing credit facilities and is accretive, on a debt-adjusted per unit basis, to cash flow, production, reserves, and net asset value.

This acquisition involved the creation of new overriding royalties, similar to the \$10 million acquisition we closed on December 21, 2009. We hope to do more of these types of acquisitions in the future as we continue our strategy of focusing on oil and gas royalties.

Operational Update

In the first quarter of 2010, drilling on our royalty lands increased 43% (on an equivalent net basis). At the end of the first quarter, there were 58 (2.0 equivalent net) licensed drilling locations on our royalty lands, up from 30 (0.9 equivalent net) at the same time last year. The increase in well licences is a positive indicator of future activity on our lands.

We participated in the drilling of five Cardium oil wells at Pembina Cardium Unit #9, where we hold a 9.97% working interest and a 0.6% royalty interest. We also drilled one Bakken oil well in Southeast Saskatchewan on our 100% mineral title lands, which will be completed after spring breakup. Horizontal drilling techniques were employed on all six wells. No production was recorded for these wells during the first quarter.

With our recent acquisitions and production additions from our 2010 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. We are still on track to invest \$24 million of capital this year, although our expenditures will be weighted more to the last half of the year. Our focus in the third and fourth quarters will be on oil development in Southeast Saskatchewan, Pembina Cardium Unit #9, and Hayter, Alberta.

Cash conserved through the DRIP (expected to be approximately \$24 million for 2010) will allow us to fund our 2010 capital program – with minimal dilutive effect. As we are now issuing DRIP units from treasury, the weighted average number of Trust Units outstanding is expected to be 58.4 million for 2010. Long-term debt at March 31 was \$78 million, up from \$45 million at December 31, as we funded the royalty acquisition in February through our credit facilities.

Business Environment

We have witnessed a gradual oil price improvement over the past 12 months, although the strength of the Canadian dollar has offset some of the benefit. Heavy oil differential prices have begun to widen in recent weeks; however, markets for heavy oil remain robust due to strong refinery demand for this product type. Export markets for western Canadian natural gas remain weak as U.S. domestic production continues to increase while demand has been slow to recover. As a result, gas storage levels remain high.

On March 11, 2010, the Alberta government completed its competitiveness review and announced changes to the royalty framework, beginning January 1, 2011. The industry's response has been generally favourable, and the improved economics may spur a return of capital investment in the Province of Alberta. Freehold will benefit from any drilling on lands where we have a gross overriding royalty interest, and from offset wells that will be drilled on our mineral title lands adjacent to Crown lands.

Industry drilling was down 29% from this time last year, but activity was the strongest seen in nine months. Another indicator of the improving business environment comes from the Petroleum Services Association of Canada (PSAC), which recently raised its 2010 Canadian industry drilling forecast to 11,250 wells. This represents a 40% increase over their original forecast of 8,000 wells issued in November 2009.

Although economic activity in Canada appears to be strengthening, we believe that the road to full global economic recovery will be long and unpredictable, influenced by many factors, including fluctuations in the U.S. dollar, the debt crisis in Greece (and potentially other countries in the European Union), and ongoing instability in the Middle East. Overall, the outlook for crude oil is more favourable than for natural gas and, with our oil-weighted, unhedged production, Freehold is well positioned to continue to benefit from any further strengthening in oil prices.

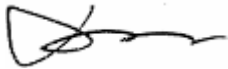
Corporate Conversion Plan

On the recommendation of the Corporate SIFT Tax Strategy Committee (a special committee of independent directors), after a thorough review of the various strategic alternatives available to maximize Unitholder value in light of the new SIFT tax beginning in 2011, our Board has approved moving forward to convert Freehold to a Corporation at the end of this year. The internal reorganization of our legal structure will require Unitholder approval as well as customary court and regulatory approvals. The detailed implementation steps are currently being defined, and we will provide periodic updates as the year progresses. We currently contemplate that the conversion will be effected within frameworks endorsed by the existing tax legislation in Canada that will permit Unitholders to exchange their Trust Units for shares of the new corporation on a non-taxable basis.

Freehold's business model will not change as a result of converting to a corporation. We recognize the strength of our royalties, which have allowed us to maintain a high payout ratio historically, and our intention is to continue on that path. As a corporation, we would expect to continue to allocate our cash flow among capital expenditures, acquisitions, periodic debt repayments, reclamation obligations, and dividends based on after-tax cash flow. Such dividends will continue to be paid on a monthly basis, with the Board reviewing the dividend policy quarterly. We currently expect that Freehold will be able to defer paying current corporate income tax until 2012.

On behalf of our Board of Directors, I would like to take this opportunity to thank our Unitholders for their support over the past 14 years. Freehold's oil and gas royalty assets have generated excellent returns to date and we believe we can continue to deliver attractive returns to our investors through dividends under a corporate model.

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



William O. Ingram
President and Chief Executive Officer

Management's Discussion and Analysis (MD&A)

The following discussion is management's opinion about the operating and financial results of Freehold Royalty Trust, Freehold Resources Ltd. and Petrovera Resources (a general partnership) (collectively, Freehold or the Trust), for the three months ended March 31, 2010 and previous periods, and the outlook for Freehold based on information available as at May 12, 2010. The financial information contained herein was based on information in the consolidated financial statements, which have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended March 31, 2010 and March 31, 2009, 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, 2009 and 2008, together with the accompanying notes.

This MD&A contains Non-GAAP measures and forward-looking statements that are intended to help readers better understand our business and prospects. Readers are cautioned that the MD&A should be read in conjunction with our disclosure under "Non-GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

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We have witnessed a gradual oil price improvement over the past 12 months, although the strength of the Canadian dollar has offset some of the benefit. Heavy oil differential prices have begun to widen recently; however, markets for heavy oil remain robust due to strong refinery demand for this product type. Export markets for western Canadian natural gas remain weak as U.S. domestic production continues to increase while demand has been slow to recover. As a result, gas storage levels remain high.

On March 11, 2010, the Alberta government completed its competitiveness review and announced changes to the royalty framework, beginning January 1, 2011. The current incentive program of 5% for the first year of production on new natural gas and conventional oil wells will become permanent with the current time and volume limits. The maximum royalty rate for conventional oil will be reduced at higher price levels from 50% to 40%. The maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50% to 36%. The transitional royalty framework will continue until its original announced expiration on December 31, 2013; however, after the end of this year, no new wells will be allowed to select the transitional royalty rates. New royalty curves, which determine royalty rates at certain commodity price levels, are to be finalized this month. The industry's response has been generally favourable, and the improved economics may spur a return of capital investment in the Province of Alberta. Freehold will benefit from any drilling on lands where we have a gross overriding royalty interest, and from offset wells that will be drilled on our mineral title lands adjacent to Crown lands.

Industry drilling was down 29% from this time last year, but activity was the strongest seen in nine months. Another indicator of the improving business environment comes from the Petroleum Services Association of Canada (PSAC), which recently raised its 2010 Canadian industry drilling forecast to 11,250 wells. This represents a 40% increase over their original forecast of 8,000 wells issued in November 2009. PSAC cites "the increase in the price of oil, the anticipated royalty changes in Alberta, and the general boost in economic activity as we emerge from the global recession" as factors contributing to an improved industry outlook.

Although economic activity in Canada appears to be strengthening, we believe that the road to full global economic recovery will be long and unpredictable, influenced by many factors, including fluctuations in the U.S. dollar, the debt crisis in Greece (and potentially other countries in the European Union), and ongoing instability in the Middle East. Overall, the outlook for crude oil is more favourable than for natural gas and, with our oil-weighted, unhedged production, Freehold is well positioned to continue to benefit from any further strengthening in oil prices.

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Royalty Acquisition

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This acquisition involved the creation of new overriding royalties, similar to the \$10 million acquisition we closed on December 21, 2009. We hope to do more of these types of acquisitions in the future as we continue our strategy of focusing on oil and gas royalties.

ROYALTY INTEREST DRILLING	Three Months Ended March 31		
	2010	2009	Change
Unitized wells			
Gross	140	127	10%
Equivalent net (1)	0.2	0.7	-71%
Non-unitized wells			
Gross	106	58	83%
Equivalent net (1)	4.1	2.3	78%
Total			
Gross	246	185	33%
Equivalent net (1)	4.3	3.0	43%

(1) Equivalent net wells are the aggregate of the numbers obtained by multiplying each gross well by our royalty interest percentage.

We have royalty interests in 2.2 million gross acres of land throughout the Western Canada Sedimentary Basin, and we receive royalties from over 200 industry operators. This diversity lowers our risk, while we benefit from the drilling activity of others. As a royalty interest owner, we do not pay any of the capital costs to drill and equip the wells for production, nor do we incur costs to operate the wells, maintain production, and ultimately restore the land to its original state. All of the costs are paid by others and we simply receive a royalty on the gross production revenue.

In the first quarter of 2010, drilling on our royalty lands increased 43% (on an equivalent net basis). At the end of the first quarter, there were 58 (2.0 equivalent net) licensed drilling locations on our royalty lands, up from 30 (0.9 equivalent net) at the same time last year. The increase in well licences is a positive indicator of future activity on our lands.

WORKING INTEREST DRILLING	Three Months Ended March 31			
	2010		2009	
	Gross	Net (1)	Gross	Net
Oil	6	1.3	4	0.5
Natural gas	1	-	1	-
Other	-	-	-	-
Total	7	1.3	5	0.5

(1) Excludes royalty interest portion on properties where Freehold has both a working interest and a royalty interest. Effective January 1, 2010, the royalty interest portion is now shown under equivalent net wells in the Royalty Interest Drilling table above.

In the first quarter of 2010, we participated in the drilling of five Cardium oil wells at Pembina Cardium Unit #9, where we hold a 9.97% working interest and a 0.6% royalty interest. We also drilled one Bakken oil well in Southeast Saskatchewan on our 100% mineral title lands, which will be completed after spring breakup. Horizontal drilling techniques were employed on all six wells.

With our recent acquisitions and production additions from our 2010 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. We are still on track to invest \$24 million of capital this year, although our expenditures will be weighted more to the last half of the year. Our focus in the third and fourth quarters will be on oil development in Southeast Saskatchewan, Pembina Cardium Unit #9, and Hayter, Alberta.

Cash conserved through the DRIP (expected to be approximately \$24 million for 2010) will allow us to fund our 2010 capital program – with minimal dilutive effect. As we are now issuing DRIP units from treasury, the weighted average number of Trust Units outstanding is expected to be 58.4 million for 2010. Long-term debt at March 31 was \$78 million, up from \$45 million at December 31, as we funded the royalty acquisition in February through our credit facilities. We anticipate reducing debt to \$60 million by year-end.

Distribution Policy

The regular monthly distribution rate is fixed at \$0.14 per Trust Unit until further notice. We will continue to review our distribution policy monthly and make adjustments, if necessary, to ensure that the distribution level is in line with funds generated from operations.

The following table summarizes our key operating assumptions for 2010, updated to reflect first quarter results and our current expectations for the remainder of the year.

2010 KEY OPERATING ASSUMPTIONS	May 12 2010	March 3 2010
Average daily production (boe/d)	7,600	7,600
Average WTI oil price (US\$/bbl)	80.00	80.00
Average AECO natural gas price (Cdn\$/Mcf)	4.20	5.00
Average exchange rate (Cdn\$/US\$)	0.96	0.96
Average operating costs (\$/boe)	4.30	4.30
Average G&A costs (\$/boe) (1)	3.20	3.20
Capital expenditures (\$ millions)	24.0	24.0
Proceeds from DRIP (\$ millions) (2)	24.0	24.0
Long-term debt at year end (\$ millions)	59.0	53.7
Weighted average Trust Units outstanding (millions)	58.4	58.4
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.

A sensitivity analysis of the potential impact of key variables on distributions to Unitholders is provided on page 20 of our 2009 annual report. 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.

Results of Operations

FUNDS GENERATED FROM OPERATIONS AND NET INCOME (\$000s, except as noted)	Three Months Ended March 31		
	2010	2009	Change
Cash provided by operating activities	27,217	21,569	26%
Changes in non-cash working capital	528	(2,950)	118%
Funds generated from operations	27,745	18,619	49%
Per Trust Unit (\$)	0.48	0.38	26%
Net income	7,674	2,391	221%
Per Trust Unit, basic and diluted (\$)	0.13	0.05	160%

Overall, our results for the first quarter reflect improved oil prices compared with the first quarter of last year, which more than offset a 3% decrease in production volumes. Payments under the Manager's long-term incentive plan (LTIP), which are payable in the first quarter every year, reduced cash provided by operating activities and funds generated from operations by \$1.5 million (Q1 2009 – \$81,000). Distributions in the first quarter were \$0.42 per Trust Unit, up 40% from the first quarter of last year.

ACCUMULATED DISTRIBUTIONS	Three Months Ended March 31	
	2010	2009
Distributions declared (\$000s)	24,265	14,841
Accumulated, beginning of period	794,898	724,418
Accumulated, end of period	819,163	739,259
Distributions per Trust Unit (\$) (1)	0.42	0.30
Accumulated, beginning of period	20.53	19.13
Accumulated, end of period	20.95	19.43

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

DISTRIBUTION ANALYSIS (\$000s, except as noted)	Three Months Ended March 31	
	2010	2009
Cash provided by operating activities	27,217	21,569
Net income	7,674	2,391
Distributions declared	24,265	14,841
Excess (shortfall) of cash provided by operating activities over distributions declared	12%	45%
Shortfall of net income over distributions declared	(68%)	(84%)

The table above illustrates the relationship between cash provided from operating activities and historical distributions, as well as net income and historical distributions. On an annual basis, the Trust has historically distributed less cash than cash provided by operating activities. This excess cash has been used to fund capital expenditures and acquisitions, and repay bank debt. Net income includes significant non-cash charges that do not affect cash flow. These charges amounted to \$21.6 million for the first quarter of 2010 (Q1 2009 – \$16.4 million). Net earnings also include fluctuations in future income taxes due to changes in tax rates and tax rules. In addition, other non-cash charges, such as depletion and depreciation on property, plant and equipment and accretion on the asset retirement obligation, do not represent the actual cost of maintaining our productive capacity given the natural declines associated with oil and gas assets. In these instances, where distributions exceed net earnings, a portion of the cash distribution paid to Unitholders may represent an economic return of the Unitholders' capital.

QUARTERLY REVIEW	2010	2009				2008		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial (\$000s, except as noted)								
Revenue, net of royalty expense	35,282	33,966	29,435	28,516	25,315	33,174	58,210	59,563
Distributions declared	24,265	23,937	16,850	14,852	14,841	54,387	37,050	30,114
Per Trust Unit (\$) (1) (2)	0.42	0.46	0.34	0.30	0.30	1.10	0.75	0.61
Net income	7,674	14,721	7,853	6,776	2,391	13,374	36,772	36,163
Per Trust Unit, basic and diluted (\$)	0.13	0.29	0.16	0.14	0.05	0.27	0.74	0.73
Cash provided by operating activities	27,217	25,937	26,215	21,938	21,569	41,672	57,380	46,379
Per Trust Unit (\$)	0.47	0.50	0.53	0.44	0.44	0.84	1.16	0.94
Funds generated from operations (3)	27,745	30,444	24,189	21,833	18,619	26,942	51,977	53,183
Per Trust Unit (\$)	0.48	0.59	0.49	0.44	0.38	0.55	1.05	1.08
Property and royalty acquisitions	38,399	9,539	-	-	-	(782)	8,475	-
Capital expenditures	2,652	4,435	7,368	1,661	2,027	3,770	9,222	2,135
Long-term debt	78,000	45,000	147,000	156,000	160,000	140,000	141,000	151,000
Trust Units outstanding								
Weighted average (000s)	57,700	51,483	49,543	49,495	49,460	49,424	49,389	49,353
At quarter end (000s)	57,926	57,503	49,582	49,531	49,495	49,459	49,424	49,388
Operating (\$/boe, except as noted)								
Daily production (boe/d)	7,331	7,402	6,994	7,295	7,522	7,779	7,613	7,674
Royalty interest production (%)	73	69	71	71	70	71	71	72
Average selling price	54.45	51.09	44.01	42.99	37.85	46.55	83.47	86.43
Operating netback (3)	49.44	45.66	42.16	37.56	33.13	42.14	79.14	81.21
Operating expenses	4.03	4.22	3.59	5.39	4.27	4.21	3.97	4.08
Working interest properties	15.10	13.69	12.59	18.78	14.27	14.31	13.51	14.37
General and administrative expenses	3.81	2.38	2.35	2.12	3.98	2.20	1.95	2.15
Benchmark Prices								
WTI crude oil (US\$/bbl)	78.71	76.19	68.30	59.62	43.08	58.69	117.98	123.98
Exchange rate (Cdn\$/US\$)	0.96	0.95	0.91	0.86	0.80	0.83	0.96	0.99
Edmonton Par crude oil (Cdn\$)	80.08	76.56	71.50	65.90	49.66	63.21	121.85	126.07
Western Canada Select/Hardisty (Cdn\$/bbl)	72.54	67.65	63.75	60.71	42.54	47.72	103.87	103.32
Light/heavy oil differential (Cdn\$/bbl) (4)	7.54	8.91	7.75	5.19	7.12	15.49	17.98	22.75
AECO natural gas (Cdn\$/Mcf)	5.36	4.23	3.02	3.66	5.62	6.78	9.24	9.35
Unit Trading Performance								
High (\$)	17.59	16.28	17.00	15.18	11.76	18.43	24.35	24.40
Low (\$)	15.08	14.02	12.75	8.70	6.87	9.15	16.01	17.51
Close (\$)	16.94	15.09	16.24	13.85	8.90	10.49	17.10	23.99
Volume (000s)	7,943	6,827	5,131	8,756	9,310	10,474	10,263	8,993

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

(2) The fourth quarters include additional distributions relating to excess income earned during the full year (\$0.06 per Trust Unit in 2009 and \$0.35 per Trust Unit in 2008).

(3) See Non-GAAP Measures.

(4) The difference between Edmonton Par and Western Canada Select/Hardisty crude oil streams.

Our quarterly performance is directly influenced by commodity prices, which are determined by supply and demand factors, weather, seasonality, global political events, general economic conditions, and changes in Canadian/U.S. dollar exchange rates. Quarterly variances in revenues, net income, cash provided by operating activities, and funds generated from operations are caused mainly by fluctuations in commodity prices and production volumes. Crude oil prices are generally determined by global supply and demand factors, but the variances do not have seasonable predictability. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is significantly influenced by weather conditions and North American natural gas inventories.

Our financial results over the last eight quarters were influenced by the following significant changes:

- WTI crude oil prices exhibited significant volatility. After reaching record levels in mid-2008, the benchmark price fell significantly in the last half of 2008 as global economic conditions deteriorated. Low prices prevailed through the first quarter of 2009 and then improved through the remainder of 2009, with further improvements in the first quarter of 2010.
- Fluctuations in U.S. to Canadian dollar exchange rates also affected our oil price realizations, resulting in both positive and negative effects on our Canadian dollar oil revenues relative to the benchmark WTI, which is referenced in U.S. dollars.
- Heavy oil differentials narrowed significantly from historical levels. U.S. demand for Canadian heavy crude has risen as imports from Mexico and Venezuela have declined. Domestic demand for heavy oil is typically highest during the summer paving season.
- AECO natural gas prices also exhibited significant volatility. Natural gas markets strengthened briefly in mid-2008; however, with supply outstripping demand, prices continued to face downward pressure, falling to a 10-year low during the third quarter of 2009. Although prices were higher in the following two quarters, natural gas fundamentals remained weak through the first quarter of 2010. Natural gas is a typically seasonal, weather-dependent fuel; demand is generally higher during the winter (for heating) and summer (for cooling), and lower during the spring and fall.
- We adjusted our monthly distributions in response to changing commodity prices. In April 2008, we raised the rate by \$0.03 to \$0.18 per Trust Unit, and raised it again in June 2008, to \$0.25 per Trust Unit. We also declared an additional distribution of \$0.35 per Trust Unit for 2008, which was paid to Unitholders on January 15, 2009. The distributions payable to Unitholders (current liability) at year-end 2008 was higher than at year-end 2009 because the additional distribution for 2008 was not paid until 2009. In January 2009, we lowered the rate to \$0.10 per Trust Unit. As oil prices strengthened, we increased the rate to \$0.12 per Trust Unit in August 2009, and increased it again in November 2009, to \$0.14 per Trust Unit. We also declared an additional distribution of \$0.06 per Trust Unit for 2009, which was paid in the fourth quarter.
- Fluctuations in our Trust Unit price resulted in corresponding changes in unit based compensation, which is based in part on the closing unit price at each quarter end.
- Under Freehold's Distribution Reinvestment Plan (DRIP), commencing with the October 2009 distribution (payable on November 15, 2009), we began issuing DRIP Trust Units from treasury instead of purchasing them in the market. Also with the November 15, 2009 distribution payment, CN Pension Trust Funds, which owns approximately 24% of Freehold's Trust Units, began to participate in the DRIP. This gave us a new source of capital to reinvest in the development of our working interest properties, reduce long-term debt, or fund acquisitions. Cash conserved through the DRIP was \$6.0 million in the first quarter of 2010.
- On December 10, 2009, Freehold closed an equity offering and issued 7.6 million Trust Units. Net proceeds of \$110.5 million were used to reduce long-term debt.
- On December 21, 2009, we closed a \$10 million royalty acquisition, and on February 17, 2010, we closed a \$39 million royalty acquisition. Both acquisitions were funded through our existing credit facilities.
- Payments under the Manager's LTIP, which are payable in the first quarter every year, reduced cash provided by operating activities and funds generated from operations by \$1.5 million in the first quarter of 2010 (Q1 2009 – \$81,000).

AVERAGE DAILY PRODUCTION	Three Months Ended March 31		
	2010	2009	Change
Royalty interest			
Oil (bbls/d)	2,930	2,834	3%
NGL (bbls/d)	258	276	-7%
Natural gas (Mcf/d)	13,117	12,975	1%
Oil equivalent (boe/d)	5,374	5,273	2%
Working interest			
Oil (bbls/d)	1,429	1,645	-13%
NGL (bbls/d)	61	67	-9%
Natural gas (Mcf/d)	2,802	3,227	-13%
Oil equivalent (boe/d)	1,957	2,250	-13%
Total Trust			
Oil (bbls/d)	4,359	4,479	-3%
NGL (bbls/d)	319	343	-7%
Natural gas (Mcf/d)	15,919	16,202	-2%
Oil equivalent (boe/d)	7,331	7,522	-3%
Number of days in period (days)	90	90	0%
Total volumes during period (Mboe)	660	677	-3%

On a boe basis, our production was down 3% in the first quarter, reflecting lower development activity levels through 2009. Effective January 1, 2010, we adjusted our method of allocating royalty interest and working interest production on properties where we have both a royalty interest and a working interest. This change affects the comparability of prior period results. The adjustment in the first quarter effectively increased royalty production by approximately 200 boe per day and reduced working interest volumes by the same amount.

Royalty interests comprised 73% (2009 Q1 – 70%) of total volumes produced in the quarter. Production from the royalty acquisition completed in December 2009 contributed 160 boe per day to first quarter volumes. Production from the royalty acquisition completed in February contributed approximately 200 boe per day in the first quarter (approximately 420 boe per day for 43 days).

Our production mix for the quarter was approximately 36% natural gas and 64% liquids (32% heavy oil, 28% light and medium oil, and 4% natural gas liquids).

Marketing and Hedging

As at March 31, 2010, we marketed approximately 40% of our royalty oil production and most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. Approximately 22% of our working interest natural gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed referenced prices. The balance of our working interest natural gas production (78%) is marketed with the operators' production.

Our production remained unhedged in the first quarter. This policy is subject to quarterly review by our Board.

AVERAGE BENCHMARK PRICES (1)	Three Months Ended		
	March 31		
	2010	2009	Change
WTI crude oil (US\$/bbl)	78.71	43.08	83%
US\$/Cdn\$ exchange rate	0.9608	0.8031	20%
Edmonton Par crude oil (Cdn\$/bbl)	80.08	49.66	61%
Western Canada Select/Hardisty (Cdn\$/bbl)	72.54	42.54	71%
Light/heavy oil differential (Cdn\$/bbl)	7.54	7.12	6%
AECO natural gas (Cdn\$/Mcf)	5.36	5.62	-5%

(1) Source for commodity prices: Canadian Association of Petroleum Producers.

Western Canada Select/Hardisty (WCS) is made up of existing Canadian heavy conventional and bitumen crude oils blended with sweet synthetic and condensate diluents. With an average API gravity of 20.5 degrees, the benchmark WCS heavy oil stream is considered a rough proxy for our average oil price realizations.

AVERAGE SELLING PRICES	Three Months Ended		
	March 31		
	2010	2009	Change
Oil (\$/bbl)	70.33	41.41	70%
NGL (\$/bbl)	52.85	40.75	30%
Oil and NGL (\$/bbl)	69.14	41.36	67%
Natural gas (\$/Mcf)	4.76	5.26	-10%
Oil equivalent (\$/boe)	54.45	37.85	44%

Our average selling prices reflect product quality and transportation differences from benchmark prices. Due to extremely low natural gas prices over the past year, processing fees, which are netted from the royalty payments, made up a larger proportion of price, further reducing our natural gas price realizations.

Revenue and Other Income

Gross revenue in the first quarter of 2010 was 37% higher than last year, mainly due to the relative strength of oil prices.

REVENUE AND OTHER INCOME (\$000s)	Three Months Ended		
	March 31		
	2010	2009	Change
Gross revenue	36,569	26,618	37%
Royalty and mineral tax expense (1)	(1,287)	(1,303)	-1%
Net revenue	35,282	25,315	39%

(1) Royalty expenses and mineral tax include all Crown charges and royalty payments to third parties.

The accompanying table demonstrates the net effect of price and volume variances on gross revenues. The major contributors to the revenue increase were higher oil prices, which more than offset lower production volumes and lower natural gas prices.

GROSS REVENUE VARIANCES (\$000s)	Three Months Ended March 31	
	2010 vs. 2009	2009 vs. 2008
Oil and NGL		
Production decrease	(895)	(1,609)
Price increase (decrease)	12,053	(15,802)
Net increase (decrease)	11,158	(17,411)
Natural gas		
Production decrease	(121)	(818)
Price increase (decrease)	(735)	(3,744)
Net increase (decrease)	(856)	(4,562)
Other (1)		
Gross revenue increase (decrease)	9,951	(21,956)

(1) Other revenue includes potash, sulphur, lease rentals, processing fees, and interest income; excludes other income.

Expenses

ROYALTY EXPENSE AND MINERAL TAX (1) (\$000s, except as noted)	Three Months Ended March 31		
	2010	2009	Change
Working interest			
Crown royalties	766	463	65%
Third party royalties	316	164	93%
Mineral tax	63	148	-57%
Working interest	1,145	775	48%
Per boe (\$)	6.50	3.83	70%
Royalty interest			
Crown royalties	-	-	-
Third party royalties	-	-	-
Mineral tax	142	528	-73%
Royalty interest	142	528	-73%
Per boe (\$)	0.29	1.11	-74%
Total Trust			
Per boe (\$)	1.95	1.92	2%

(1) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.

We do not incur Crown or third party royalty expenses on production from our royalty interest properties. As the royalty owner, we receive the royalty as income from other companies. Crown royalty rates, on our working interest properties, were slightly higher in 2010, due to higher oil prices. Mineral tax is payable annually to the Crown, in the first quarter of the year. Mineral tax on our royalty lands was lower this year due to a review of allowable mineral tax charges.

OPERATING EXPENSES (\$000s, except as noted)	Three Months Ended March 31		
	2010	2009	Change
Working interest	2,658	2,890	-8%
Per boe (\$)	15.10	14.27	6%
Royalty interest (1)	-	-	-
Per boe (\$)	-	-	-
Total operating expenses	2,658	2,890	-8%
Total Trust (\$/boe)	4.03	4.27	-6%

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

Operating expenses were down 8% as we had slightly reduced costs common to industry as well as minor reductions due to prior period adjustments. On a per boe basis, operating expenses on our working interest properties were 6% higher than last year because we allocated approximately 200 boe per day of production from working interest to royalty interest (see discussion under Average Daily Production).

We manage one of the largest portfolios of oil and gas royalties in Canada. Our royalty lands extend from northeastern British Columbia to southern Ontario. As a royalty owner, we share in production revenue without incurring the operational costs, risks, and responsibilities typically associated with oil and gas operations. The following table demonstrates the advantage of our royalty lands which yield higher operating netbacks than our working interest properties. Royalty interests contributed 73% of total volumes produced in the first quarter of 2010.

NETBACK ANALYSIS (\$000s)	Three months ended March 31, 2010		
	Royalty Interest	Working Interest	Total Trust
Gross revenue (1)	25,650	10,919	36,569
Royalty expense and mineral tax (2)	(142)	(1,145)	(1,287)
Net revenue	25,508	9,774	35,282
Operating expense	-	(2,658)	(2,658)
Operating netback	25,508	7,116	32,624

(1) Gross revenue includes potash, sulphur, lease rentals, processing fees, and interest income.

(2) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.

Our operating netback per boe improved in the first quarter of 2010, mainly due to higher oil prices.

OPERATING NETBACK (\$/boe)	Three Months Ended March 31		
	2010	2009	Change
Gross revenue (1)	55.42	39.32	41%
Royalty expense and mineral tax (2)	(1.95)	(1.92)	2%
Operating expenses	(4.03)	(4.27)	-6%
Operating netback	49.44	33.13	49%

(1) Gross revenue includes potash, sulphur, lease rentals, processing fees and interest income.

(2) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.

GENERAL AND ADMINISTRATIVE EXPENSES (\$000s, except as noted)	Three Months Ended March 31		
	2010	2009	Change
	G&A expenses	2,514	2,694
Per boe (\$)	3.81	3.98	-4%
As a percentage of revenue	7%	10%	-30%

G&A expenses include direct costs incurred by the Trust and reimbursement of G&A expenses incurred by the Manager on behalf of the Trust (see Related Party Transactions). We have significant land administration, accounting and auditing requirements to administer and collect royalty payments, including systems to track development activity on the royalty lands.

UNIT BASED AND OTHER COMPENSATION (\$000s, except as noted)	Three Months Ended March 31		
	2010	2009	Change
	Manager's long-term incentive plan	1,098	39
Deferred trust unit plan	236	250	-6%
Retirement benefit	23	-	-
Unit based and other compensation	1,357	289	370%
Per boe (\$)	2.06	0.43	379%
As a percentage of revenue	4%	1%	300%

Manager's Long-Term Incentive Plan (LTIP)

After a three-year vesting period, employees of the Manager receive cash compensation in relation to the value of a specified number of notional units. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. The LTIP liability is estimated at the end of each quarter based on the quarter-end Trust Unit price and performance factors; the related compensation charges are recognized over the vesting period. The 2007 LTIP grants vested in January 2010 and \$1.5 million of unit based compensation was paid out in the first quarter of 2010. Non-cash charges were higher this year because a higher period end Trust Unit price increased the plan's value.

Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors and are redeemable for an equal number of Trust Units (less tax withholdings) any time after the director's retirement. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. The annual grant occurs in the first quarter.

Retirement Benefit Plan

The Trust pays its proportionate share of a retirement benefit for certain employees of the Manager. The retirement benefit is payable in four equal instalments upon retirement after reaching the age of 65. Service costs are amortized on a straight-line basis over the expected average remaining service lifetime.

INTEREST AND FINANCING (\$000s, except as noted)	Three Months Ended March 31		
	2010	2009	Change
	Interest and financing expense	743	866
Per boe (\$)	1.13	1.28	-12%

Interest and financing expense declined 14% in the first quarter of 2010 due to significantly lower debt levels this year.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSES (\$000s, except as noted)	Three Months Ended March 31		
	2010	2009	Change
Depletion and depreciation	15,653	15,876	-1%
Accretion of asset retirement obligation	104	81	28%
Total depletion, depreciation and accretion expenses	15,757	15,957	-1%
Per boe (\$)	23.87	23.57	1%

Depletion of oil and natural gas properties (including the capitalized portion of the asset retirement obligation) and depreciation of equipment are provided for on a unit-of-production basis using estimated proved reserves.

MANAGEMENT FEES (Paid in Trust Units)	Three Months Ended March 31		
	2010	2009	Change
Trust Units issued in payment of management fees	41,924	35,654	18%
Ascribed value (\$000s) (1)	710	317	124%
Per boe (\$)	1.08	0.47	130%

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

The Manager of the Trust receives a management fee in Trust Units. The issue of 7.9 million Trust Units from treasury in the fourth quarter of 2009 and 0.4 million Trust Units from treasury in the first quarter of 2010 resulted in pro-rata increases in the management fee, in accordance with the management agreement (see Unitholders' Capital).

Future Income Tax

At the end of the first quarter of 2010, we had a future income tax liability of \$39.9 million (Q1 2009 – \$42.3 million). We measure future income tax assets and liabilities under the SIFT tax rules. As we near January 1, 2011, the effective rates applied to the reversal of temporary differences approaches the complete phase-in of the SIFT tax rates. As a result, we recorded a non-cash charge of \$3.8 million for the first quarter of 2010.

Liquidity and Capital Resources

ACQUISITIONS AND CAPITAL EXPENDITURES (\$000s, except as noted)	Three Months Ended March 31		
	2010	2009	Change
Property and royalty acquisitions (net)	38,399	-	-
Capital expenditures	2,652	2,027	31%
Change in reclamation fund	188	92	104%
	41,239	2,119	1846%

We have no capital requirements with respect to our royalty properties. Our capital expenditure obligations (with respect to our working interest properties) are deducted from funds generated from operations prior to determining distributions to Unitholders. Expenditures in the first quarter included \$38.3 million on acquisitions and \$2.7 million on development of our working interest properties. We also recorded a \$0.1 million charge related to prior year acquisitions.

COMPONENTS OF WORKING CAPITAL (\$000s)	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
	2010	2009	2009	2009	2009
Cash	152	432	311	369	546
Current portion of deferred compensation	-	-	-	-	34
Accounts receivable	24,244	24,056	19,622	21,315	21,870
Current assets	24,396	24,488	19,933	21,684	22,450
Distributions payable to Unitholders	(8,110)	(8,050)	(5,950)	(4,953)	(4,950)
Current portion of unit based compensation	(1,932)	(1,643)	(1,559)	(743)	(131)
Accounts payable and accrued liabilities	(16,460)	(17,877)	(20,243)	(13,824)	(15,780)
Current liabilities	(26,502)	(27,570)	(27,752)	(19,520)	(20,861)
Working capital (1)	(2,106)	(3,082)	(7,819)	2,164	1,589

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

In the oil and gas industry, accounts receivable from industry partners are typically settled in the following month. However, due to administrative complexity, payments to royalty owners are often delayed longer. Working capital at each period end can vary due to volume and price changes during the period.

DEBT ANALYSIS (\$000s)	As at March 31		
	2010	2009	Change
Long-term debt	78,000	160,000	-51%
Short-term debt	-	-	-
Total debt	78,000	160,000	-51%
Working capital	2,106	(1,589)	233%
Net debt obligations	80,106	158,411	-49%

We have a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks and 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 and standby fees. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. At March 31, 2010, we had \$132 million of available capacity under our credit facilities.

Our borrowing base is dependent on our lenders' annual review and interpretation of our reserves and future commodity prices. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice. This review was recently completed with no changes to our borrowing base.

FINANCIAL LEVERAGE AND COVERAGE RATIOS (1)	As at March 31		
	2010	2009	Change
Net debt to funds generated from operations (times)	0.8	1.1	-27%
Net debt to distributions (times)	1.0	1.2	-17%
Distributions to interest expense (times)	17.5	24.0	-27%
Net debt to net debt plus equity (%)	22%	43%	-49%

(1) Funds generated from operations, distributions, and interest expense are 12-months trailing.

Under our credit facilities, we are restricted from making distributions if we are or would be in default under the facilities or if our borrowings thereunder exceed our borrowing base. As at March 31, 2010, the Trust was in compliance with all such covenants.

Unitholders' Capital

On October 26, 2009, the Board of Directors approved the monthly issuance of Trust Units from treasury for the Distribution Reinvestment Plan (DRIP), effective for the October distribution payable on November 15, 2009 and thereafter. Previously, Trust Units issued in relation to the DRIP were purchased through the facilities of the Toronto Stock Exchange at prevailing market prices. CN Pension Trust Funds, which owns approximately 24% of our Trust Units, began participating in the DRIP, effective with the distribution paid on November 15, 2009.

DISTRIBUTIONS PAID THROUGH THE DISTRIBUTION REINVESTMENT PLAN (\$000s)	Three Months Ended March 31	
	2010	2009
Total distributions paid	24,205	39,568
Distributions paid in cash	18,181	39,568
Distributions paid through the DRIP	6,024	-

In the first quarter of 2010, participation in Freehold's DRIP was approximately 25%. We issued 381,369 Trust Units with an ascribed value of \$6.0 million, based on the weighted average closing price for the 10 trading days preceding each distribution date. In the first quarter last year, DRIP participation was less than 1% and no Trust Units were issued from treasury. The cash conserved through a higher participation rate in the DRIP and by issuing Trust Units from treasury instead of purchasing them in the market gives us a new source of capital (with only a minor dilutive effect), which can be used to develop our working interest properties, reduce long-term debt, or fund acquisitions.

TRUST UNITS OUTSTANDING	Three Months Ended March 31		
	2010	2009	Change
Weighted average			
Basic	57,700,094	49,459,825	17%
Diluted	57,752,457	49,526,680	17%
At period end	57,926,236	49,495,083	17%

On March 31, 2010, 41,924 Trust Units were issued from treasury for the quarterly management fee. As at March 31, 2010 there were 57,926,236 Trust Units outstanding and as at May 12, 2010, there were 58,045,036 Trust Units outstanding.

On January 1, 2010, the Board granted 13,916 deferred trust units to eligible directors as part of their annual compensation. Each eligible director received 1,988 deferred trust units and the Chair of the Board received 3,976 deferred trust units (see Unit Based and Other Compensation). As at March 31, 2010, there were 68,632 deferred trust units outstanding and at May 12, 2010, there were 69,180 deferred trust units outstanding.

Foreign Ownership Update

Our Trust Indenture provides that not more than 49% of the Trust's Units can be held by non-residents. We monitor foreign ownership levels on a regular basis through declarations from Unitholders and geographical searches. Based on geographical data as of March 15, 2010 (the record date for our 2010 annual meeting of Unitholders), we estimate that approximately 85% of the Trust's Units are held by Canadian residents, with the remaining 15% held by non-residents. While we believe that these results are reasonable estimations, the inability of all public issuers to obtain the residency information of their beneficial holders means that issuers must rely upon the information provided to the transfer agent. As a result, the residency information is subject to the accuracy provided by third party data and by system limitations. Accordingly, the reported level of Canadian ownership is subject to these limitations, and the level of Canadian ownership can change at any time without notice.

Related Party Transactions

The Trust does not have any employees. The Manager of the Trust is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager recovers its general and administrative, long-term incentive plan costs and retirement benefit costs and receives a quarterly management fee paid in Trust Units.

For the three months ended March 31, 2010, we issued 41,924 Trust Units (2009 – 35,654 Trust Units) as a management fee to the Manager pursuant to a management agreement. The ascribed value of \$0.7 million (2009 – \$0.3 million) is based on the closing price of the Trust Units on the last trading day of the quarter.

For the three months ended March 31, 2010, the Manager charged the Trust \$1.8 million in general and administrative costs (2009 – \$2.2 million). At March 31, 2010, there was \$0.4 million (2009 – \$0.6 million) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was the amount of consideration established and agreed to by the Trust and the Manager.

Contingencies

Two legal actions are outstanding:

- In the second quarter of 2009, a statement of claim was filed against the Trust for \$9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, the Trust has assessed the claim, believes it has no merit, and intends to aggressively defend itself in the claim. The claim's outcome is not determinable; therefore, no liability has been recorded in the financial statements.
- In the fourth quarter of 2009, a judgment of \$2.1 million in Freehold's favour was received and recorded in other income. The claim was based on Freehold's assertion of incorrect royalty payments and production from a terminated lease. Cash payment in full was received. The defendant has appealed this judgment but Freehold and its legal counsel believe there are no grounds for a successful appeal. The appeal's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

Accounting and Control Matters

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. Except as discussed in this MD&A, we are not aware of any trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

New Accounting Standards

International Financial Reporting Standards (IFRS)

As discussed in our 2009 annual MD&A, we are continuing to prepare for the adoption of IFRS effective January 1, 2011. In preparation for the transition from current Canadian GAAP to IFRS, we have assigned internal staff to lead the conversion project, retained an external advisor to assist us, and continue to involve our auditors in the process. Our transition plan addresses resources required; employee training; analysis of accounting standard differences; accounting policy determination; evaluation of information system requirements; and an impact assessment on operations, internal controls over financial reporting, and disclosures.

We are currently analyzing the accounting policy choices available under IFRS and assessing the impact of certain accounting standards. Our business impact study has identified areas of high and medium impact on the Trust. IFRS 1, *First-Time Adoption of International Financial Reporting Standards* provides entities with a number of exemptions to avoid full retroactive application. Some of the major accounting policy considerations are identified in our 2009 annual MD&A; however more may emerge as the project continues.

We plan to make final decisions on accounting policies, information technology requirements and training requirements by the third quarter of 2010, while internal controls and disclosures issues will not be finalized until early in 2011. We will provide a progress update on our IFRS conversion project in our next quarterly MD&A.

Internal Controls

Freehold is required to comply with National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*. The certification of interim filings requires us to disclose in the MD&A any changes in the Trust's internal controls over financial reporting that have materially affected, or are reasonably likely to materially affect the Trust's internal control over financial reporting. We confirm that no such changes were made to the internal controls over financial reporting during the three months ended March 31, 2010. The Chief Executive Officer and Chief Financial Officer have signed form 52-109F2, *Certification of Interim Filings*, which can be found on SEDAR at www.sedar.com.

Additional Information

Additional information about Freehold, including our annual information form (AIF), is available on SEDAR at www.sedar.com and on our website at www.freeholdtrust.com.

Forward-Looking Statements

This document offers our assessment of Freehold's future plans and operations as at May 12, 2010, and contains forward-looking statements that we believe allow readers to better understand our business and prospects.

Forward-looking statements are contained in the Message to Unitholders and under Business Environment, and include our expectations for improving economic conditions, drilling activity in Canada, industry drilling and development activity on our royalty lands, reserves and reserve life index from our acquisitions in 2010, participation in the DRIP and use of cash conserved through the DRIP, estimated capital expenditures and the timing thereof, long-term debt, average production and production from royalty land, our outlook for commodity prices including supply and demand factors relating to crude oil heavy oil, and natural gas, key operating assumptions, acquisition opportunities, future income tax, and our corporate conversion plans.

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 MD&A, 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 and use of cash conserved through 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. The key operating assumptions with respect to the forward-looking statements referred to above are detailed in our discussion of the Business Environment.

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 MD&A, 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 (see Operating Netback).

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 (see Funds Generated From Operations and Net Income).

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 (see Debt Analysis).

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.

Consolidated Balance Sheets

(\$000s) (unaudited)	March 31, 2010	December 31, 2009
Assets		
Current assets:		
Cash	\$ 152	\$ 432
Accounts receivable	24,244	24,056
	24,396	24,488
Reclamation fund	2,449	2,261
Deferred long-term compensation (note 6)	2,339	1,954
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$528,792 (2009 - \$513,139)	415,276	389,837
	\$ 444,460	\$ 418,540
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	\$ 8,110	\$ 8,050
Accounts payable and accrued liabilities	16,460	17,877
Current portion of unit based and other compensation payable (note 6)	1,932	1,643
	26,502	27,570
Asset retirement obligation	7,292	7,160
Unit based and other compensation payable (note 6)	3,374	3,702
Long-term debt (note 3)	78,000	45,000
Future income tax liability	39,941	36,136
Unitholders' equity:		
Unitholders' capital (note 4)	691,713	684,979
Contributed surplus (note 6)	995	759
Deficit	(403,357)	(386,766)
	289,351	298,972
	\$ 444,460	\$ 418,540

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Income, Comprehensive Income and Deficit

(unaudited) (\$000s, except per unit and weighted average data)	Three Months Ended March 31,	
	2010	2009
Revenue:		
Royalty income and working interest sales	\$ 36,569	\$ 26,618
Royalty expense and mineral tax	(1,287)	(1,303)
	35,282	25,315
Expenses:		
Operating	2,658	2,890
General and administrative	2,514	2,694
Unit based and other compensation (note 6)	1,357	289
Interest and financing	743	866
Depletion and depreciation	15,653	15,876
Accretion of asset retirement obligation	104	81
Management fee (note 5)	710	317
	23,739	23,013
Income before taxes	11,543	2,302
Income and capital taxes	64	101
Future income tax (reduction)	3,805	(190)
	3,869	(89)
Net income and comprehensive income	7,674	2,391
Deficit, beginning of period	(386,766)	(348,027)
Distributions declared	(24,265)	(14,841)
Deficit, end of period	\$ (403,357)	\$ (360,477)
Net income per Trust Unit, basic and diluted	\$ 0.13	\$ 0.05
Weighted average number of Trust Units:		
Basic	57,700,094	49,459,825
Diluted	57,752,457	49,526,680

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Cash Flows

(\$000s) (unaudited)	Three Months Ended March 31	
	2010	2009
Cash provided by (used in):		
Operating:		
Net income	\$ 7,674	\$ 2,391
Items not involving cash:		
Depletion and depreciation	15,653	15,876
Unit based and other compensation (note 6)	1,357	289
Future income tax (reduction)	3,805	(190)
Accretion of asset retirement obligation	104	81
Trust Units issued in lieu of management fee	710	317
Expenditures on unit based and other compensation (note 6)	(1,545)	(81)
Expenditures on reclamation	(13)	(64)
	27,745	18,619
Changes in non-cash working capital	(528)	2,950
	27,217	21,569
Financing:		
Long-term debt	33,000	20,000
Distributions paid	(18,181)	(39,568)
	14,819	(19,568)
Investing:		
Property and royalty acquisitions	(38,399)	-
Capital expenditures	(2,652)	(2,027)
Change in reclamation fund	(188)	(92)
Changes in non-cash working capital	(1,077)	127
	(42,316)	(1,992)
Increase (decrease) in cash	(280)	9
Cash, beginning of period	432	537
Cash, end of period	\$ 152	\$ 546

See accompanying notes to interim consolidated financial statements.

Notes to Interim Consolidated Financial Statements

For the three months ended March 31, 2010 and 2009.

1. Significant Accounting Policies

The interim consolidated financial statements of Freehold Royalty Trust (Freehold or the Trust) 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, 2009 and should be read in conjunction with the audited consolidated financial statements and notes for the year ended December 31, 2009. In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal recurring nature necessary to present fairly the Trust's financial position as at March 31, 2010 and the results of its operations and cash flows for the three months then ended.

2. Property Acquisition

On February 17, 2010, Freehold closed an acquisition of certain royalty interests in Alberta, Saskatchewan, and British Columbia for \$38.3 million, including adjustments. The acquisition was effective October 1, 2009 and was funded through existing credit facilities. For the three months ended March 31, 2010, Freehold incurred an additional \$0.1 million of prior year acquisition adjustments.

3. Long-Term Debt

Freehold has a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which \$78 million was drawn at March 31, 2010. In addition, Freehold has available a \$15 million extendible revolving operating facility. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice. The facilities are extendible annually with the latest review completed in May 2010.

Freehold's borrowing base is dependent on the lenders' annual review and interpretation of our reserves and future commodity prices. In the event that the lenders do not consent to an extension, the revolving credit facility would 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, which is May 2011.

Borrowings under the facilities bear interest at the bank's prime lending rate, banker's acceptance or LIBOR rates plus applicable margins and standby fees.

4. Unitholders' Capital

	March 31, 2010		December 31, 2009	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	57,502,943	684,979	49,459,429	567,310
Issued for Distribution Reinvestment Plan	381,369	6,024	260,740	3,906
Issued in lieu of management fee (note 5)	41,924	710	148,597	2,018
Issued for director's retirement	-	-	15,427	222
Issued for equity offering, net of issue costs	-	-	7,618,750	115,424
Issue costs, net of tax effect	-	-	-	(3,901)
Balance, end of period	57,926,236	691,713	57,502,943	684,979

For the three months ended March 31, 2010, Freehold issued 381,369 Trust Units from treasury for the Distribution Reinvestment Plan (DRIP). The ascribed value of \$6.0 million is based on the weighted average closing price for the 10 trading days preceding each distribution date.

5. Related Party Transactions

The Trust does not have any employees. The Manager of the Trust is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager recovers its general and administrative, long-term incentive plan costs and retirement benefit costs and receives a quarterly management fee paid in Trust Units.

For the three months ended March 31, 2010, Freehold issued 41,924 Trust Units (2009 – 35,654 Trust Units) as a management fee to the Manager pursuant to a management agreement. The ascribed value of \$0.7 million (2009 – \$0.3 million) is based on the closing price of the Trust Units on the last trading day of the quarter.

For the three months ended March 31, 2010, the Manager charged the Trust \$1.8 million in general and administrative costs (2009 – \$2.2 million). At March 31, 2010, there was \$0.4 million (2009 – \$0.6 million) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was the amount of consideration established and agreed to by the Trust and the Manager.

6. Unit Based and Other Compensation

(a) Manager's Long-Term Incentive Plan (LTIP)

After a three-year vesting period, employees of the Manager receive cash compensation in relation to the value of a specified number of notional units. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. For the three months ended March 31, 2010, Freehold expensed \$1.1 million (2009 – \$39,000) as unit based compensation. At March 31, 2010, Freehold recorded \$2.3 million (2009 – \$0.2 million) as a deferred long-term compensation asset, representing the portion of the liability not yet charged to earnings. In addition, Freehold has accrued \$3.1 million (2009 – \$0.3 million) as a long-term liability and \$1.8 million (2009 – \$0.1 million) as a current liability. The 2007 LTIP grants of \$1.5 million were paid out in the quarter.

(b) Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. As at March 31, 2010, there were 68,632 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

For the three months ended March 31, 2010, Freehold expensed \$236,000 (2009 – \$250,000) of unit based compensation with a corresponding increase to contributed surplus.

CONTRIBUTED SURPLUS (\$000s)	March 31 2010	December 31 2009
Balance, beginning of period	759	722
Trust Unit incentive compensation expense	236	352
Grants redeemed on director's retirement	-	(315)
Balance, end of period	995	759

(c) Retirement Benefit

The Trust participates in its proportionate share of a retirement benefit for certain employees of the Manager. The retirement benefit is payable in four equal instalments upon retirement and reaching the age of 65. Service costs are amortized on a straight-line basis over the expected average remaining service lifetime. For the three months ended March 31, 2010, Freehold expensed \$23,000 (2009 – \$0) with a corresponding increase to the obligation.

RECONCILIATION OF CHANGES IN THE PLAN'S BENEFIT OBLIGATIONS (\$000s)	March 31 2010	December 31 2009
Accrued benefit obligation, beginning of period	405	-
Current service cost	23	504
Payments	-	(99)
Accrued benefit obligation, end of period	428	405

7. Supplemental Cash Flow Disclosure

CASH EXPENSES PAID (\$000s)	Three Months Ended March 31	
	2010	2009
Interest	713	780
Taxes	64	191

8. Contingencies

- (a) In the second quarter of 2009, a statement of claim was filed against the Trust for \$9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, the Trust has assessed the claim, believes it has no merit and intends to aggressively defend itself in the claim. The claim's outcome is not determinable; therefore, no liability has been recorded in the financial statements.
- (b) In the fourth quarter of 2009, a judgment of \$2.1 million in Freehold's favour was received. The claim was based on Freehold's assertion of incorrect royalty payments and production from a terminated lease. Cash payment in full was received. The defendant has appealed this judgment but Freehold and its legal counsel believe there are no grounds for a successful appeal. The appeal's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

Corporate Information

Board of Directors

D. Nolan Blades ⁽¹⁾⁽²⁾⁽³⁾
President

Sunny Gables Holdings Ltd.

Harry S. Campbell, Q.C. ⁽³⁾⁽⁴⁾⁽⁵⁾
Vice-Chair

Burnet, Duckworth & Palmer, LLP

Tullio Cedraschi ⁽³⁾⁽⁴⁾
Corporate Director

Peter T. Harrison ⁽⁵⁾
Manager, Common Stocks (North America)
CN Investment Division

William O. Ingram
President and Chief Executive Officer
Rife Resources Ltd.

P. Michael Maher ⁽¹⁾⁽²⁾⁽⁴⁾
Professor, Haskayne School of Business
University of Calgary

David J. Sandmeyer ⁽³⁾⁽⁵⁾
Corporate Director

Rodger A. Tourigny ⁽¹⁾⁽²⁾⁽³⁾
President
Tourigny Management Ltd.

Stock Exchange
Toronto Stock Exchange
Trading Symbol: FRU.UN

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Toll Free: 1-888-267-6555
Fax: (403) 267-6598
Email: service@computershare.com

- (1) Audit Committee
- (2) Compensation Committee
- (3) Corporate SIFT Tax Strategy Committee
- (4) Governance Committee
- (5) Reserves Committee

Officers

D. Nolan Blades
Chair of the Board

William O. Ingram
President and Chief Executive Officer

Michael J. Okrusko
Senior Vice-President, Special Projects

Garry W. Bieber
Vice-President, Production

J. Frank George
Vice-President, Exploitation

Darren G. Gunderson
Vice-President, Finance and Chief
Financial Officer

Michael J. Stone
Vice-President, Land

Michael J. Mogan
Controller

Karen C. Taylor
Manager, Investor Relations and
Corporate Secretary

Legal Counsel
Burnet Duckworth & Palmer, LLP
Calgary, Alberta

Auditors
KPMG, LLP
Calgary, Alberta

Bankers
Canadian Imperial Bank of Commerce
Calgary, Alberta

Royal Bank of Canada
Calgary, Alberta

The Toronto-Dominion Bank
Calgary, Alberta

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Karen C. Taylor
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Toll Free: 1-888-257-1873
Email: ir@freeholdtrust.com

Website
www.freeholdtrust.com

2010 First Quarter
Trading Summary
High – \$17.59
Low – \$15.08
Close – \$16.94
Volume Traded – 7.9 million
Trust Units Outstanding – 57.9 million

2010 First Quarter
Distributions Declared

<u>Record Date</u>	<u>Payment Date</u>	<u>Per Trust Unit</u>
Jan. 31, 2010	Feb. 15, 2010	\$0.14
Feb. 28, 2010	Mar. 15, 2010	\$0.14
Mar. 31, 2010	Apr. 15, 2010	<u>\$0.14</u>
		<u>\$0.42</u>

Tax information and historical
distributions are available on our
website.