2 Quarterly Report

Period ended June 30, 2010

Freehold
ROYALTY TRUST

Freehold Royalty Trust Announces 2010 Second Quarter Results

RESULTS AT A GLANCE	Three Months Ended June 30			Six Months Ended June 30		
Financial ($000s, except as noted)	2010	2009	Change	2010	2009	Change
Gross revenue	32,424	29,164	11%	68,993	55,782	24%
Net income	9,214	6,776	36%	16,888	9,167	84%
Per Trust Unit, basic and diluted ($)	0.16	0.14	16%	0.29	0.19	57%
Cash provided by operating activities	28,757	21,938	31%	55,974	43,507	29%
Per Trust Unit ($)	0.49	0.44	11%	0.97	0.88	10%
Funds generated from operations (1)	25,197	21,833	15%	52,942	40,452	31%
Per Trust Unit ($)	0.43	0.44	-2%	0.91	0.82	11%
Capital expenditures	4,735	1,661	185%	7,387	3,688	100%
Property and royalty acquisitions (net)	71	-	-	38,470	-	-
Distributions declared	24,436	14,852	65%	48,701	29,693	64%
Per Trust Unit ($) (2)	0.42	0.30	40%	0.84	0.60	40%
Long-term debt, period end	73,000	156,000	-53%	73,000	156,000	-53%
Unitholders' equity, period end	281,005	200,561	40%	281,005	200,561	40%
Trust Units (000s) (3)	58,112	49,495	17%	57,907	49,478	17%
Operating						
Average daily production (boe/d) (4)	7,655	7,295	5%	7,494	7,408	1%
Average price realizations ($/boe) (4)	45.56	42.99	6%	49.89	40.39	24%
Operating netback ($/boe) (1) (4)	40.96	37.56	9%	45.08	35.32	28%

(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).

August Distribution Announcement

The Board of Directors has declared the August distribution of $0.14 per Trust Unit, which will be paid on September 15, 2010 to Unitholders of record on August 31, 2010 (ex-distribution date August 27, 2010). Including the September 15 payment, our 12-month trailing cash distributions total $1.70 per Trust Unit. The regular monthly distribution will remain fixed at $0.14 per Trust Unit until further notice.

Message to Unitholders

We are pleased to report strong financial and operating results for the second quarter of 2010. Gross revenue increased 11% and funds generated from operations rose 15%, reflecting higher production and improved oil prices compared with last year. Distributions have remained level at $0.14 per Trust Unit since December 2009. Production rose 5% in the second quarter, aided by royalty acquisitions completed in December 2009 and February 2010. Freehold's production, which remains unhedged, is oil weighted and Unitholders have benefited from the relative strength of oil prices.

Crude Oil and Natural Gas Markets

Crude oil prices have improved significantly from last year. Quoted in U.S. dollars, the monthly average WTI has ranged between $70 and $85 per barrel. Global markets for crude oil remain volatile, with prices fluctuating in reaction to continuing global uncertainties, particularly the European debt crisis and weak economic conditions in the United States. As a result, we have lowered our WTI pricing assumption for 2010 by 4%.

Markets for heavy oil remain strong, although price differentials for heavy oil have widened following the recent completion of the linefill for TransCanada's Keystone pipeline.

Natural gas supply continues to outstrip demand in North America, keeping natural gas prices low. The second quarter was a typical shoulder season, marked by the end of winter heating demand. Despite improving demand for industrial use and summer cooling, natural gas storage levels remain above the five-year average, largely due to continued U.S. shale gas drilling. Indications are that natural gas prices will remain weak through the third and fourth quarters, although weather could be a wild card. As a result we have lowered our natural gas pricing assumption for 2010 by 5%.

Royalty Lands and Industry Drilling

In May, the Alberta government unveiled changes to the base royalty curves for conventional oil and gas and announced further initiatives to encourage development of Alberta's unconventional and deep resource pools. Freehold will benefit from drilling on any Alberta Crown lands where we have gross overriding royalty interests, and from offset wells that will be drilled on our mineral title lands adjacent to Crown lands. The industry's response to the royalty changes has been favourable, as evidenced by high prices paid at recent Alberta Crown land sales and increased drilling activity in the second quarter of 2010. Despite an extremely wet spring, the well count in western Canada (as reported by the Canadian Association of Oilwell Drilling Contractors) rose 54% from the second quarter last year.

Drilling on our royalty lands is also up significantly from last year, and we are encouraged that industry operators have not stopped drilling for natural gas on our royalty lands despite weak natural gas prices. The increase in well licences is a further positive indicator of future activity on our lands. As at June 30, 2010, there were 119 (4.1 equivalent net) licensed drilling locations on our royalty lands, up from 43 (1.7 equivalent net) locations at the half way point last year.

We are very pleased with the performance to date of our recent royalty acquisitions. These acquisitions involved the creation of new overriding royalties. Ongoing drilling on the lands will contribute to our future production. We are actively pursuing opportunities to acquire additional royalty interests and have $137 million of available capacity under our current credit facilities, which could be used for acquisitions.

Working Interest Properties

On our working interest properties, we drilled three (0.5 net) Dina oil wells at Hayter, two (0.9 net) Bakken oil wells in Southeast Saskatchewan, and one (0.1 net) Cardium oil well at Pembina Cardium Unit #9. We also participated in one (0.2 net) natural gas well at Willesden Green. All were drilled using horizontal drilling technology, and four of the seven wells were completed using multi-stage fracture stimulation techniques. These wells will add to our production in the last half of the year. Capital investment in the first half of 2010 amounted to $7.4 million.

Outlook

Capital investment in 2010 is expected to total $24.0 million. Expenditures will be higher in the last half of the year as we focus on oil development in our three core areas: Southeast Saskatchewan, Hayter, and Pembina Cardium Unit #9. With slightly lower pricing assumptions for both oil and natural gas, we will pay down less debt than previously anticipated by the end of the year. Our other key operating assumptions (detailed in our second quarter MD&A) remain unchanged.

Cash preserved through our distribution reinvestment plan (expected to be approximately $24 million for 2010) 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.

Corporate Conversion Plans

As announced on May 12, 2010, we are moving forward with our plans to convert Freehold to a corporation at the end of 2010. Further details about the conversion will be announced in the coming months.

We currently contemplate that the conversion will permit Unitholders to exchange their Trust Units for common shares of the new corporation on a non-taxable basis. In addition, we expect that Freehold will not pay corporate income tax until 2012.

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 the same path. As a corporation, we expect to continue to allocate our cash flow among capital expenditures, acquisitions, periodic debt repayments – and dividends based on after-tax cash flow. We expect to pay dividends on a monthly basis, with the Board reviewing the dividend policy quarterly.

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 and six months ended June 30, 2010 and previous periods, and the outlook for Freehold based on information available as at August 11, 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 June 30, 2010 and June 30, 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.

Business Environment

WTI crude oil prices have improved significantly from last year. Priced in U.S. dollars, the monthly average WTI has ranged between $70 and $85 this year. Global markets for crude oil remain volatile, with prices fluctuating in reaction to continuing global uncertainties, particularly the European debt crisis and weak economic conditions in the United States. As a result, we have lowered our WTI pricing assumption for 2010 by 4%. Markets for heavy oil remain strong, although price differentials for heavy oil have widened following the recent completion of the linefill for TransCanada's Keystone pipeline.

Natural gas supply continues to outstrip demand in North America, keeping natural gas prices low. The second quarter was a typical shoulder season, marked by the end of winter heating demand. Despite improving demand for industrial use and summer cooling, natural gas storage levels remain above the five-year average, largely due to continued U.S. shale gas drilling. Indications are that natural gas prices will remain weak through the third and fourth quarters, although weather could be a wild card. As a result, we have lowered our natural gas pricing assumption for 2010 by 5%.

On May 27, 2010, the Alberta government unveiled changes to the base royalty curves for conventional oil and gas, effective January 1, 2011. The changes to the oil and gas royalty curves are in keeping with the announcements previously made in March 2010. The government also announced further initiatives to encourage development of Alberta's unconventional and deep resource pools. The Natural Gas Deep Drilling Program, implemented in 2008, is now a permanent feature of the Alberta royalty framework. The new Emerging Resources and Technologies Initiative aims to encourage new exploration, development and production from deeper, higher cost natural gas wells; gas resources within coal seams; shale gas; and horizontal oil and gas wells. Additional benefits have been extended to accommodate these higher risk plays.

The industry's response to the royalty changes has been favourable, as evidenced by high prices paid at recent Alberta Crown land sales and increased drilling activity in the second quarter of 2010. Despite an extremely wet spring, the well count in western Canada (as reported by the Canadian Association of Oilwell Drilling Contractors) rose 54% from the second quarter last year.

Freehold will benefit from drilling on any Alberta Crown 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. We have royalty interests in 2.2 million gross acres of land throughout the Western Canada Sedimentary Basin and 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, or 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.

ROYALTY INTEREST DRILLING	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	Change	2010	2009	Change
Non-unitized wells						
Gross	11	8	38%	117	66	77%
Equivalent net (1)	0.7	0.4	75%	4.8	2.7	78%
Unitized wells						
Gross	8	92	-91%	148	219	-32%
Equivalent net (1)	-	0.2	-100%	0.2	0.9	-78%
Total						
Gross	19	100	-81%	265	285	-7%
Equivalent net (1)	0.7	0.6	17%	5.0	3.6	39%

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

Drilling on our royalty lands has improved significantly from last year (on an equivalent net basis), driven by active development on lands where we recently acquired gross royalty interests. As at June 30, 2010, there were 119 (4.1 equivalent net) licensed drilling locations on our royalty lands, up from 43 (1.7 equivalent net) locations at the same time last year. The increase in well licences is also a positive indicator of future activity on our lands.

On unitized lands, we generally have small royalty interests in hundreds of wells and rely on public databases to monitor activity levels. The decline in unitized drilling in the second quarter could be the result of weak natural gas prices, delays in reporting, or wet spring conditions.

WORKING INTEREST DRILLING	Three Months Ended June 30				Six Months Ended June 30			
	2010		2009		2010		2009	
	Gross	Net (1)	Gross	Net	Gross	Net (1)	Gross	Net
Oil	6	1.5	2	0.2	12	2.8	6	0.7
Natural gas	1	0.2	-	-	2	0.2	1	-
Other	-	-	-	-	-	-	-	-
Total	7	1.7	2	0.2	14	3.0	7	0.7

(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 second quarter of 2010, we drilled three (0.5 net) Dina oil wells at Hayter, two (0.9 net) Bakken oil wells in Southeast Saskatchewan, and one (0.1 net) Cardium oil well at Pembina Cardium Unit #9. We also participated in one (0.2 net) natural gas well at Willesden Green. All were drilled using horizontal drilling technology, and four of the seven wells were completed using multi-stage fracture stimulation techniques. These wells will be placed on production during the third quarter, adding to our production in the last half of the year.

Guidance Update

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.

Capital investment in 2010 is expected to total $24.0 million. Expenditures will be higher in the last half of the year as we focus on oil development in our three core areas: Southeast Saskatchewan, Hayter, and Pembina Cardium Unit #9. With slightly lower pricing assumptions for both oil and natural gas, we will pay down less debt than previously anticipated by the end of the year.

Cash preserved through our distribution reinvestment plan (expected to be approximately $24 million for 2010) 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.

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

2010 KEY OPERATING ASSUMPTIONS	August 11 2010	May 12 2010	March 3 2010
Average daily production (boe/d)	7,600	7,600	7,600
Average WTI oil price (US$/bbl)	77.00	80.00	80.00
Average AECO natural gas price (Cdn$/Mcf)	4.00	4.20	5.00
Average exchange rate (Cdn$/US$)	0.96	0.96	0.96
Average operating costs ($/boe)	4.30	4.30	4.30
Average G&A costs ($/boe) (1)	3.20	3.20	3.20
Capital expenditures ($ millions)	24.0	24.0	24.0
Proceeds from DRIP ($ millions) (2)	24.0	24.0	24.0
Long-term debt at year end ($ millions)	69.0	59.0	53.7
Weighted average Trust Units outstanding (millions)	58.4	58.4	58.4
Estimated portion of distributions taxable as income (%)	90-100%	90-100%	90-100%

(1) Excludes unit based and other compensation, and corporate reorganization costs.
(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.

Corporate Conversion Update

As announced on May 12, 2010, we are moving forward with our plans to convert Freehold to a corporation at the end of 2010. We currently contemplate that the conversion will permit Unitholders to exchange their Trust Units for common shares of the new corporation on a non-taxable basis. In addition, we expect that Freehold will not pay corporate income tax until 2012.

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 the same path. As a corporation, we expect to continue to allocate our cash flow among capital expenditures, acquisitions, periodic debt repayments, and dividends based on after-tax cash flow. We expect to pay dividends on a monthly basis, with the Board reviewing the dividend policy quarterly.

Results of Operations

FUNDS GENERATED FROM OPERATIONS AND NET INCOME	Three Months Ended June 30			Six Months Ended June 30		
($000s, except as noted)	2010	2009	Change	2010	2009	Change
Cash provided by operating activities	28,757	21,938	31%	55,974	43,507	29%
Changes in non-cash working capital	(3,560)	(105)		(3,032)	(3,055)	
Funds generated from operations	25,197	21,833	15%	52,942	40,452	31%
Per Trust Unit ($)	0.43	0.44	-2%	0.91	0.82	11%
Net income	9,214	6,776	36%	16,888	9,167	84%
Per Trust Unit, basic and diluted ($)	0.16	0.14	16%	0.29	0.19	57%

Overall, our results for the second quarter and year to date reflect improved oil prices compared with last year, along with slightly higher production volumes due to acquisitions completed in December 2009 and February 2010. Distributions declared in 2010 were significantly higher than last year because of higher funds generated from operations. On a per Trust Unit basis, distributions have remained level at $0.14 per Trust Unit since December 2009.

ACCUMULATED DISTRIBUTIONS	Three Months Ended June 30		Six Months Ended June 30	
	2010	2009	2010	2009
Distributions declared ($000s)	24,436	14,852	48,701	29,693
Accumulated, beginning of period	819,163	739,259	794,898	724,418
Accumulated, end of period	843,599	754,111	843,599	754,111
Distributions per Trust Unit ($) (1)	0.42	0.30	0.84	0.60
Accumulated, beginning of period	20.95	19.43	20.53	19.13
Accumulated, end of period	21.37	19.73	21.37	19.73

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

DISTRIBUTION ANALYSIS	Three Months Ended June 30		Six Months Ended June 30	
($000s, except as noted)	2010	2009	2010	2009
Cash provided by operating activities	28,757	21,938	55,974	43,507
Net income	9,214	6,776	16,888	9,167
Distributions declared	24,436	14,852	48,701	29,693
Excess (shortfall) of cash provided by operating activities over distributions declared	18%	48%	15%	47%
Shortfall of net income over distributions declared	(62%)	(54%)	(65%)	(69%)

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 $16.2 million for the second quarter of 2010 (Q2 2009 – $15.1 million) and $37.8 million for the first half of 2010 (2009 – $31.4 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	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial ($000s, except as noted)								
Revenue, net of royalty expense	31,524	35,282	33,966	29,435	28,516	25,315	33,174	58,210
Distributions declared	24,436	24,265	23,937	16,850	14,852	14,841	54,387	37,050
Per Trust Unit ($) (1) (2)	0.42	0.42	0.46	0.34	0.30	0.30	1.10	0.75
Net income	9,214	7,674	14,721	7,853	6,776	2,391	13,374	36,772
Per Trust Unit, basic and diluted ($)	0.16	0.13	0.29	0.16	0.14	0.05	0.27	0.74
Cash provided by operating activities	28,757	27,217	25,937	26,215	21,938	21,569	41,672	57,380
Per Trust Unit ($)	0.49	0.47	0.50	0.53	0.44	0.44	0.84	1.16
Funds generated from operations (3)	25,197	27,745	30,444	24,189	21,833	18,619	26,942	51,977
Per Trust Unit ($)	0.43	0.48	0.59	0.49	0.44	0.38	0.55	1.05
Property and royalty acquisitions (net)	71	38,399	9,539	-	-	-	(782)	8,475
Capital expenditures	4,735	2,652	4,435	7,368	1,661	2,027	3,770	9,222
Long-term debt	73,000	78,000	45,000	147,000	156,000	160,000	140,000	141,000
Trust Units outstanding								
Weighted average (000s)	58,112	57,700	51,483	49,543	49,495	49,460	49,424	49,389
At quarter end (000s)	58,335	57,926	57,503	49,582	49,531	49,495	49,459	49,424
Operating ($/boe, except as noted)								
Daily production (boe/d)	7,655	7,331	7,402	6,994	7,295	7,522	7,779	7,613
Royalty interest production (%)	73	73	69	71	71	70	71	71
Average selling price	45.56	54.45	51.09	44.01	42.99	37.85	46.55	83.47
Operating netback (3)	40.96	49.44	45.66	42.16	37.56	33.13	42.14	79.14
Operating expenses	4.29	4.03	4.22	3.59	5.39	4.27	4.21	3.97
Working interest properties	15.99	15.10	13.69	12.59	18.78	14.27	14.31	13.51
General and administrative expenses	2.56	3.81	2.38	2.35	2.12	3.98	2.20	1.95
Benchmark Prices								
WTI crude oil (US$/bbl)	78.03	78.71	76.19	68.30	59.62	43.08	58.69	117.98
Exchange rate (Cdn$/US$)	0.97	0.96	0.95	0.91	0.86	0.80	0.83	0.96
Edmonton Par crude oil (Cdn$)	75.19	80.08	76.56	71.50	65.90	49.66	63.21	121.85
Western Canada Select/Hardisty (Cdn$/bbl)	65.62	72.54	67.65	63.75	60.71	42.54	47.72	103.87
Light/heavy oil differential (Cdn$/bbl) (4)	9.57	7.54	8.91	7.75	5.19	7.12	15.49	17.98
AECO natural gas (Cdn$/Mcf)	3.86	5.36	4.23	3.02	3.66	5.62	6.78	9.24
Unit Trading Performance								
High ($)	18.05	17.59	16.28	17.00	15.18	11.76	18.43	24.35
Low ($)	15.31	15.08	14.02	12.75	8.70	6.87	9.15	16.01
Close ($)	15.84	16.94	15.09	16.24	13.85	8.90	10.49	17.10
Volume (000s)	6,029	7,943	6,827	5,131	8,756	9,310	10,474	10,263

(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 half 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.
- Over the past two years, heavy oil differentials have narrowed significantly from historical levels as U.S. demand for Canadian heavy crude has risen as imports from Mexico and Venezuela have declined. Heavy oil differentials widened in the second quarter of 2010, following completion of the linefill for the Keystone pipeline. Domestic demand for heavy oil is typically highest during the summer paving season.
- AECO natural gas prices also exhibited significant volatility, falling to a 10-year low during the third quarter of 2009. With supply outstripping demand, prices remained weak through the first half 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 adjust our monthly distributions in response to changing commodity prices. In 2008, we declared an additional distribution of $0.35 per Trust Unit, which was paid to Unitholders on January 15, 2009. We also declared an additional distribution of $0.06 per Trust Unit for 2009, which was paid in December. 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 distribution 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. This rate was maintained through the first half of 2010.
- 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 currently 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 preserved through the DRIP is approximately $2.0 million per month.
- On December 10, 2009, we 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 June 30			Six Months Ended June 30		
	2010	2009	Change	2010	2009	Change
Royalty interest						
Oil (bbls/d)	2,969	2,824	5%	2,950	2,829	4%
NGL (bbls/d)	308	265	16%	283	271	4%
Natural gas (Mcf/d)	13,926	12,671	10%	13,524	12,822	5%
Oil equivalent (boe/d)	5,598	5,201	8%	5,487	5,237	5%
Working interest						
Oil (bbls/d)	1,270	1,446	-12%	1,349	1,545	-13%
NGL (bbls/d)	103	70	47%	82	68	21%
Natural gas (Mcf/d)	4,102	3,465	18%	3,456	3,346	3%
Oil equivalent (boe/d)	2,057	2,094	-2%	2,007	2,171	-8%
Total Trust						
Oil (bbls/d)	4,239	4,270	-1%	4,299	4,374	-2%
NGL (bbls/d)	411	335	23%	365	339	8%
Natural gas (Mcf/d)	18,028	16,136	12%	16,980	16,168	5%
Oil equivalent (boe/d)	7,655	7,295	5%	7,494	7,408	1%
Number of days in period (days)	91	91	0%	181	181	0%
Total volumes during period (Mboe)	697	664	5%	1,356	1,341	1%

On a boe basis, production was up 5% in the second quarter, reflecting acquisitions completed in December 2009 and February 2010. These royalty acquisitions contributed approximately 170 and 450 boe per day, respectively, to second quarter volumes.

Royalty interests comprised 73% (Q2 2009 – 71%) of total volumes produced in the quarter. 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 effectively increased royalty production by approximately 200 boe per day for the six months ended June 30, 2010, reducing working interest volumes by the same amount.

Our production mix for the first half of 2010 was approximately 38% natural gas and 62% liquids (31% heavy oil, 26% light and medium oil, and 5% natural gas liquids).

Marketing and Hedging

As at June 30, 2010, we marketed approximately 38% of our royalty oil production and most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. Approximately 16% 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 (84%) is marketed with the operators' production.

Our production remains unhedged, subject to quarterly review by our Board.

AVERAGE BENCHMARK PRICES (1)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	Change	2010	2009	Change
WTI crude oil (US$/bbl)	78.03	59.62	31%	78.37	51.35	53%
US$/Cdn$ exchange rate	0.9734	0.8579	13%	0.9671	0.8305	16%
Edmonton Par crude oil (Cdn$/bbl)	75.19	65.90	14%	77.63	57.78	34%
Western Canada Select/Hardisty (Cdn$/bbl)	65.62	60.71	8%	69.08	51.62	34%
Light/heavy oil differential (Cdn$/bbl)	9.57	5.19	84%	8.55	6.16	39%
AECO natural gas (Cdn$/Mcf)	3.86	3.66	5%	4.61	4.64	-1%

(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 June 30			Six Months Ended June 30		
	2010	2009	Change	2010	2009	Change
Oil ($/bbl)	62.94	59.07	7%	66.66	50.08	33%
NGL ($/bbl)	48.50	37.41	30%	50.39	39.09	29%
Oil and NGL ($/bbl)	61.66	57.50	7%	65.39	49.29	33%
Natural gas ($/Mcf)	3.44	3.02	14%	4.06	4.14	-2%
Oil equivalent ($/boe)	45.56	42.99	6%	49.89	40.39	24%

Our average selling prices reflect product quality and transportation differences from benchmark prices.

Revenue and Other Income

Gross revenue was up 11% in the second quarter and up 24% in the first half of 2010, due to the relative strength of oil prices, along with higher royalty interest production volumes.

REVENUE AND OTHER INCOME	Three Months Ended June 30			Six Months Ended June 30		
($000s)	2010	2009	Change	2010	2009	Change
Gross revenue	32,424	29,164	11%	68,993	55,782	24%
Royalty and mineral tax expense (1)	(900)	(648)	39%	(2,187)	(1,951)	12%
Net revenue	31,524	28,516	11%	66,806	53,831	24%

(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 and higher production volumes, which more than offset lower natural gas prices.

GROSS REVENUE VARIANCES	Three Months Ended June 30		Six Months Ended June 30	
($000s)	2010 vs. 2009	2009 vs. 2008	2010 vs. 2009	2009 vs. 2008
Oil and NGL				
Production increase (decrease)	254	(530)	(577)	(2,371)
Price increase (decrease)	1,746	(19,932)	13,736	(35,501)
Net increase (decrease)	2,000	(20,462)	13,159	(37,872)
Natural gas				
Production increase (decrease)	593	(460)	596	(1,273)
Price increase (decrease)	610	(10,901)	(248)	(14,650)
Net increase (decrease)	1,203	(11,361)	348	(15,923)
Other (1)	57	(314)	(296)	(298)
Gross revenue increase (decrease)	3,260	(32,137)	13,211	(54,093)

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

Expenses

ROYALTY EXPENSE AND MINERAL TAX (1)	Three Months Ended June 30			Six Months Ended June 30		
($000s, except as noted)	2010	2009	Change	2010	2009	Change
Working interest						
Crown royalties	610	356	71%	1,377	820	68%
Third party royalties	227	179	27%	543	343	58%
Mineral tax	56	108	-48%	120	256	-53%
Working interest	893	643	39%	2,040	1,419	44%
Per boe ($)	4.77	3.37	42%	5.62	3.61	56%
Royalty interest						
Crown royalties	-	-	-	-	-	-
Third party royalties	-	-	-	-	-	-
Mineral tax	7	5	40%	147	532	-72%
Royalty interest	7	5	40%	147	532	-72%
Per boe ($)	0.01	0.01	0%	0.15	0.56	-73%
Total Trust	900	648	39%	2,187	1,951	12%
Per boe ($)	1.29	0.98	32%	1.61	1.46	10%

(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 royalties (on our working interest properties) were 68% 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	Three Months Ended June 30			Six Months Ended June 30		
($000s, except as noted)	2010	2009	Change	2010	2009	Change
Working interest	2,993	3,578	-16%	5,651	6,468	-13%
Per boe ($)	15.99	18.78	-15%	15.56	16.46	-5%
Royalty interest (1)	-	-	-	-	-	-
Per boe ($)	-	-	-	-	-	-
Total operating expenses	2,993	3,578	-16%	5,651	6,468	-13%
Total Trust ($/boe)	4.29	5.39	-20%	4.17	4.82	-13%

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

Operating expenses in the second quarter last year included approximately $800,000 ($1.21 per boe) of expenses relating to 2005 to 2008. Excluding this one time adjustment, operating expenses in 2010 were consistent with last year, although slightly higher on a per boe basis as a result of slightly lower working interest production volumes this year.

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 six months of 2010.

NETBACK ANALYSIS	Six months ended June 30, 2010		
($000s)	Royalty Interest	Working Interest	Total Trust
Gross revenue (1)	48,425	20,568	68,993
Royalty expense and mineral tax (2)	(147)	(2,040)	(2,187)
Net revenue	48,278	18,528	66,806
Operating expense	-	(5,651)	(5,651)
Operating netback	48,278	12,877	61,155

(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.

On a per boe basis, our operating netback improved in 2010, mainly due to higher oil prices and higher royalty interest production.

OPERATING NETBACK	Three Months Ended June 30			Six Months Ended June 30		
($/boe)	2010	2009	Change	2010	2009	Change
Gross revenue (1)	46.54	43.93	6%	50.86	41.60	22%
Royalty expense and mineral tax (2)	(1.29)	(0.98)	32%	(1.61)	(1.46)	10%
Operating expenses	(4.29)	(5.39)	-20%	(4.17)	(4.82)	-13%
Operating netback	40.96	37.56	9%	45.08	35.32	28%

(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	Three Months Ended June 30			Six Months Ended June 30		
($000s, except as noted)	2010	2009	Change	2010	2009	Change
G&A expenses	1,786	1,404	27%	4,300	4,098	5%
Per boe ($)	2.56	2.12	21%	3.17	3.06	4%
As a percentage of gross revenue	6%	5%	20%	6%	7%	-14%

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. G&A expenses in the second quarter of 2010 include one-time costs associated with the transition to international financial reporting standards (IFRS) and our planned corporate reorganization at the end of this year.

UNIT BASED AND OTHER COMPENSATION	Three Months Ended June 30			Six Months Ended June 30		
($000s, except as noted)	2010	2009	Change	2010	2009	Change
Manager's long-term incentive plan	364	844	-57%	1,462	883	66%
Deferred trust unit plan	29	21	38%	265	271	-2%
Retirement benefit	12	-	-	35	-	-
Unit based and other compensation	405	865	-53%	1,762	1,154	53%
Per boe ($)	0.58	1.30	-55%	1.30	0.86	51%
As a percentage of gross revenue	1%	3%	-67%	3%	2%	50%

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. For the year to date, non-cash charges were higher in 2010 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	Three Months Ended June 30			Six Months Ended June 30		
($000s, except as noted)	2010	2009	Change	2010	2009	Change
Interest and financing expense	1,281	1,550	-17%	2,024	2,416	-16%
Per boe ($)	1.84	2.34	-21%	1.49	1.80	-17%

Interest and financing expense in the second quarter is typically higher than other periods as it includes rollover fees related to the annual renewal of our credit facilities. In 2010, interest and financing expense declined due to significantly lower debt levels this year.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSES ($000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	Change	2010	2009	Change
Depletion and depreciation	17,144	15,764	9%	32,797	31,640	4%
Accretion of asset retirement obligation	106	82	29%	210	163	29%
Total depletion, depreciation and accretion expenses	17,250	15,846	9%	33,007	31,803	4%
Per boe ($)	24.76	23.87	4%	24.33	23.72	3%

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 June 30			Six Months Ended June 30		
	2010	2009	Change	2010	2009	Change
Trust Units issued in payment of management fees	42,201	35,654	18%	84,125	71,308	18%
Ascribed value ($000s) (1)	669	494	35%	1,379	811	70%
Per boe ($)	0.96	0.74	30%	1.02	0.60	70%

(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 from treasury of 7.9 million Trust Units in the fourth quarter of 2009, 0.4 million Trust Units in the first quarter of 2010, and 0.4 million Trust Units in the second 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 June 30, 2010, we had a future income tax liability of $37.8 million (June 30, 2009 – $40.2 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. For the second quarter of 2010, we recorded a non-cash recovery of $2.1 million, and for the year to date, we recorded a $1.7 million charge.

Liquidity and Capital Resources

ACQUISITIONS AND CAPITAL EXPENDITURES ($000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	Change	2010	2009	Change
Property and royalty acquisitions (net)	71	-	-	38,470	-	-
Capital expenditures	4,735	1,661	185%	7,387	3,688	100%
Change in reclamation fund	32	100	-68%	220	192	15%
	4,838	1,761	175%	46,077	3,880	1088%

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. In the second quarter, we invested $4.7 million on development of working interest properties. Expenditures in the first half included $38.5 million on acquisitions and $7.4 million on development of our working interest properties.

COMPONENTS OF WORKING CAPITAL ($000s)	June 30 2010	Mar. 31 2010	Dec. 31 2009	Sept. 30 2009	June 30 2009
Cash	779	152	432	311	369
Accounts receivable	20,729	24,244	24,056	19,622	21,315
Current assets	21,508	24,396	24,488	19,933	21,684
Distributions payable to Unitholders	(8,167)	(8,110)	(8,050)	(5,950)	(4,953)
Current portion of unit based compensation	(1,867)	(1,932)	(1,643)	(1,559)	(743)
Accounts payable and accrued liabilities	(16,414)	(16,460)	(17,877)	(20,243)	(13,824)
Current liabilities	(26,448)	(26,502)	(27,570)	(27,752)	(19,520)
Working capital (1)	(4,940)	(2,106)	(3,082)	(7,819)	2,164

(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 June 30 2010	As at December 31 2009	Change
Long-term debt	73,000	45,000	62%
Short-term debt	-	-	-
Total debt	73,000	45,000	62%
Working capital	4,940	3,082	60%
Net debt obligations	77,940	48,082	62%

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 June 30, 2010, we had $137 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 June 30 2010	As at December 31 2009	Change
Net debt to funds generated from operations (times)	0.7	0.5	40%
Net debt to distributions (times)	0.9	0.7	29%
Distributions to interest expense (times)	20.9	15.1	38%
Net debt to net debt plus equity (%)	22%	14%	57%

(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 June 30, 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 currently 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	Three Months Ended June 30		Six Months Ended June 30	
($000s)	2010	2009	2010	2009
Total distributions paid	24,379	14,848	48,584	54,416
Distributions paid in cash	(18,201)	(14,848)	(36,382)	(54,416)
Distributions paid through the DRIP	6,178	-	12,202	-

In the second quarter of 2010, participation in Freehold's DRIP was approximately 25%. We issued 366,109 Trust Units with an ascribed value of $6.2 million, based on the weighted average closing price for the 10 trading days preceding each distribution date. For the year to date, we issued 747,478 Trust Units with an ascribed value of $ 12.2 million. In the first half last year, DRIP participation was less than 1% and no Trust Units were issued from treasury. The cash preserved 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, which can be used to develop our working interest properties, reduce long-term debt, or fund acquisitions.

TRUST UNITS OUTSTANDING	Three Months Ended June 30			Six Months Ended June 30		
	2010	2009	Change	2010	2009	Change
Weighted average						
Basic	58,112,432	49,495,475	17%	57,907,402	49,477,748	17%
Diluted	58,166,501	49,564,608	17%	57,960,623	49,545,749	17%
At period end	58,334,546	49,530,737	18%	58,334,546	49,530,737	18%

On June 30, 2010, 42,201 Trust Units were issued from treasury for the quarterly management fee. As at June 30, 2010, there were 58,334,546 Trust Units outstanding and as at August 11, 2010, there were 58,462,976 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 June 30, 2010, there were 70,336 deferred trust units outstanding and at August 11, 2010, there were 70,925 deferred trust units outstanding.

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 from the Trust a portion of its general and administrative, long-term incentive plan, and retirement benefit costs. The manager also receives a quarterly management fee paid in Trust Units.

For the three months ended June 30, 2010, Freehold issued 42,201 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 – $0.5 million) is based on the closing price of the Trust Units on the last trading day of the quarter. The total issued for the six months ended June 30, 2010 was 84,125 Trust Units (2009 – 71,308) with an ascribed value of $1.4 million (2009 – $0.8 million).

For the three months ended June 30, 2010, the Manager charged the Trust $1.3 million in general and administrative costs (2009 – $1.2 million). The total for the six months ended June 30, 2010 was $3.2 million (2009 – $3.3 million). At June 30, 2010, there was $0.4 million (2009 – $0.4 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 defend itself aggressively 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. The adoption will require restatement, for comparative purposes, of amounts reported for the year ended December 31, 2010, including our opening balance sheet as at January 1, 2010.

Knowledgeable staff are leading the conversion project, assisted by an external advisor, and we continue to involve our auditors in the process. Our transition plan addresses resources required, 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 have made significant progress in many of the areas, including assessing the impact of accounting policy choices under IFRS, educating the Board, and training employees. We have also made preliminary conclusions under IFRS 1, *First-Time Adoption of International Financial Reporting Standards*, which provides exemptions from full retroactive application. Some of the major considerations with respect to accounting policy decisions are identified below; however, further review is required as the project continues. In the third quarter, we will be reviewing our accounting policy choices and opening balance sheet with our auditors. Final accounting policy decisions will be presented to the audit committee and board of directors for approval following our auditor review.

- For property, plant and equipment (PP&E), we have made some preliminary decisions under IAS 16 regarding asset valuation, cash generating units (CGUs), and depletion and depreciation. All of Freehold's petroleum and natural gas interests should be classified as PP&E assets with the exception of exploration and evaluation (E&E) assets. Under IFRS 1, we expect to use the option of recording opening values at their deemed cost, which is the net book value under Canadian GAAP at January 1, 2010, rather than retrospectively applying the requirements of IAS 16. We anticipate allocating these values based on the reserve value at that point in time. Depletion and depreciation should occur at the CGU level with a choice to use either proved or proved plus probable reserves.
- Freehold has limited E&E assets, mostly in the form of undeveloped land. The original valuation of these assets will be affected by IFRS 1, whereby we will use an option to use their deemed cost which is the net book value under Canadian GAAP at January 1, 2010. A policy will be formulated for determining when to treat these assets under IAS16 rather than IFRS 6.
- Impairment testing for Freehold's PP&E and E&E assets will occur at a CGU level. Impairment is tested at reporting dates if there is an indication that an asset may be impaired. Impairments may be reversed if the impairment indicators have reversed.
- For our asset retirement obligations, we expect to use the option under IFRS 1 to revalue our obligation at January 1, 2010, using the appropriate discount rate at that date, rather than retrospectively revaluing each year as required under IAS 37. We expect to use a risk free discount rate, which will increase the liability on our balance sheet.
- For share-based payments, we do not expect to apply IFRS 2 retrospectively on equity settled instruments fully vested or cash settled payments transacted by January 1, 2010. Freehold will no longer be able to carry the deferred asset on the balance sheet, which will reduce the amount of the liability.
- For Unitholders' equity, our preliminary assessment indicates that our Trust Units are equity, which would not require a change from the current accounting.

We will continue to monitor all business agreements, including lending agreements, to ensure that they remain unaffected by the changeover to IFRS. Information technology systems continue to be evaluated, but appear to be adequate with minor modifications. Internal controls over financial reporting will be assessed as accounting policy choices are finalized to ensure that additional controls and procedures are in place for future reporting requirements. Disclosure controls and procedures will also be evaluated to ensure that we keep stakeholders' informed of the transition.

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 six months ended June 30, 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 August 11, 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 in the MD&A under Business Environment and Accounting and Control Matters, and 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;
- the expected impact of international financial reporting standards on our reported results; 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 preserved 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)	June 30, 2010	December 31, 2009
Assets		
Current assets:		
Cash	$ 779	$ 432
Accounts receivable	20,729	24,056
	21,508	24,488
Reclamation fund	2,481	2,261
Deferred long-term compensation (note 6)	1,893	1,954
Petroleum and natural gas interests, net of accumulated depletion and depreciation of $545,936 (2009 - $513,139)	403,013	389,837
	$ 428,895	$ 418,540
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	$ 8,167	$ 8,050
Accounts payable and accrued liabilities	16,414	17,877
Current portion of unit based and other compensation payable (note 6)	1,867	1,643
	26,448	27,570
Asset retirement obligation	7,303	7,160
Unit based and other compensation payable (note 6)	3,335	3,702
Long-term debt (note 3)	73,000	45,000
Future income tax liability	37,804	36,136
Unitholders' equity:		
Unitholders' capital (note 4)	698,560	684,979
Contributed surplus (note 6)	1,024	759
Deficit	(418,579)	(386,766)
	281,005	298,972
	$ 428,895	$ 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 June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenue:				
Royalty income and working interest sales	$ 32,424	$ 29,164	$ 68,993	$ 55,782
Royalty expense and mineral tax	(900)	(648)	(2,187)	(1,951)
	31,524	28,516	66,806	53,831
Expenses:				
Operating	2,993	3,578	5,651	6,468
General and administrative	1,786	1,404	4,300	4,098
Unit based and other compensation (note 6)	405	865	1,762	1,154
Interest and financing	1,281	1,550	2,024	2,416
Depletion and depreciation	17,144	15,764	32,797	31,640
Accretion of asset retirement obligation	106	82	210	163
Management fee (note 5)	669	494	1,379	811
	24,384	23,737	48,123	46,750
Income before taxes	7,140	4,779	18,683	7,081
Income and capital taxes	63	100	127	201
Future income tax (reduction)	(2,137)	(2,097)	1,668	(2,287)
	(2,074)	(1,997)	1,795	(2,086)
Net income and comprehensive income	9,214	6,776	16,888	9,167
Deficit, beginning of period	(403,357)	(360,477)	(386,766)	(348,027)
Distributions declared	(24,436)	(14,852)	(48,701)	(29,693)
Deficit, end of period	$ (418,579)	$ (368,553)	$ (418,579)	$ (368,553)
Net income per Trust Unit, basic and diluted	$ 0.16	$ 0.14	$ 0.29	$ 0.19
Weighted average number of Trust Units:				
Basic	58,112,432	49,495,475	57,907,402	49,477,748
Diluted	58,166,501	49,564,608	57,960,623	49,545,749

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Cash Flows

($000s) (unaudited)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Cash provided by (used in):				
Operating:				
Net income	$ 9,214	$ 6,776	$ 16,888	$ 9,167
Items not involving cash:				
Depletion and depreciation	17,144	15,764	32,797	31,640
Unit based and other compensation (note 6)	405	865	1,762	1,154
Future income tax (reduction)	(2,137)	(2,097)	1,668	(2,287)
Accretion of asset retirement obligation	106	82	210	163
Trust Units issued in lieu of management fee	669	494	1,379	811
Expenditures on unit based and other compensation (note 6)	(34)	-	(1,579)	(81)
Expenditures on reclamation	(170)	(51)	(183)	(115)
	25,197	21,833	52,942	40,452
Changes in non-cash working capital	3,560	105	3,032	3,055
	28,757	21,938	55,974	43,507
Financing:				
Long-term debt	(5,000)	(4,000)	28,000	16,000
Distributions paid	(18,201)	(14,848)	(36,382)	(54,416)
	(23,201)	(18,848)	(8,382)	(38,416)
Investing:				
Property and royalty acquisitions	(71)	-	(38,470)	-
Capital expenditures	(4,735)	(1,661)	(7,387)	(3,688)
Change in reclamation fund	(32)	(100)	(220)	(192)
Changes in non-cash working capital	(91)	(1,506)	(1,168)	(1,379)
	(4,929)	(3,267)	(47,245)	(5,259)
Increase (decrease) in cash	627	(177)	347	(168)
Cash, beginning of period	152	546	432	537
Cash, end of period	$ 779	$ 369	$ 779	$ 369

See accompanying notes to interim consolidated financial statements.

Notes to Interim Consolidated Financial Statements

For the three months and six months ended June 30, 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 June 30, 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.

3. Long-Term Debt

Freehold has a $195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which $73 million was drawn at June 30, 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

	June 30, 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	747,478	12,202	260,740	3,906
Issued in lieu of management fee (note 5)	84,125	1,379	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	58,334,546	698,560	57,502,943	684,979

For the three months ended June 30, 2010, Freehold issued 366,109 Trust Units from treasury for the Distribution Reinvestment Plan (DRIP) with an ascribed value of $6.2 million. The ascribed value is based on the weighted average closing price for the 10 trading days preceding each distribution date. For the six months ended June 30, 2010, Freehold issued 747,478 Trust Units from treasury for the DRIP with an ascribed value of $12.2 million.

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 from the Trust a portion of its general and administrative, long-term incentive plan, and retirement benefit costs. The Manager also receives a quarterly management fee paid in Trust Units.

For the three months ended June 30, 2010, Freehold issued 42,201 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 – $0.5 million) is based on the closing price of the Trust Units on the last trading day of the quarter. The total issued for the six months ended June 30, 2010 was 84,125 Trust Units (2009 – 71,308) with an ascribed value of $1.4 million (2009 – $0.8 million).

For the three months ended June 30, 2010, the Manager charged the Trust $1.3 million in general and administrative costs (2009 – $1.2 million). The total for the six months ended June 30, 2010 was $3.2 million (2009 – $3.3 million). At June 30, 2010, there was $0.4 million (2009 – $0.4 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 June 30, 2010, Freehold expensed $0.4 million (2009 – $0.8 million) as unit based compensation. The total for the six months ended June 30, 2010 was $1.5 million (2009 – $0.9 million). At June 30, 2010, Freehold recorded $1.9 million (2009 – $1.7 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 – $1.9 million) as a long-term liability and $1.7 million (2009 – $0.7 million) as a current liability. The 2007 LTIP grants of $1.5 million were paid out in the first quarter 2010.

(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 June 30, 2010, there were 70,336 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 June 30, 2010, Freehold expensed $29,000 (2009 – $21,000) of unit based compensation with a corresponding increase to contributed surplus. The total for the six months ended June 30, 2010 was $265,000 (2009 – $271,000).

CONTRIBUTED SURPLUS ($000s)	June 30 2010	December 31 2009
Balance, beginning of period	759	722
Trust Unit incentive compensation expense	265	352
Grants redeemed on director's retirement	-	(315)
Balance, end of period	1,024	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 June 30, 2010, Freehold expensed $12,000 (2009 – $0) with a corresponding increase to the obligation. The total for the six months ended June 30, 2010 was $35,000 (2009 – $0).

RECONCILIATION OF CHANGES IN THE PLAN'S BENEFIT OBLIGATIONS ($000s)	June 30 2010	December 31 2009
Accrued benefit obligation, beginning of period	405	-
Current service cost	35	504
Payments	(34)	(99)
Accrued benefit obligation, end of period	406	405

7. Supplemental Cash Flow Disclosure

CASH EXPENSES PAID	Three Months Ended June 30		Six Months Ended June 30	
($000s)	2010	2009	2010	2009
Interest	1,362	1,617	2,075	2,427
Taxes	(84)	101	(20)	292

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.

9. Comparative figures

Certain comparative figures have been reclassified to conform to the current year presentation.

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

Trustee and Transfer Agent

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600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8
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

Reserve Evaluators

Trimble Engineering Associates Ltd.
Calgary, Alberta

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Website

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2010 Second Quarter Trading Summary

High – $18.05
Low – $15.31
Close – $15.84
Volume Traded – 6.0 million
Trust Units Outstanding – 58.3 million

2010 Second Quarter Distributions Declared

Record Date	Payment Date	Per Trust Unit
April 30, 2010	May 15, 2010	$0.14
May 31, 2010	June 15, 2010	$0.14
June 30, 2010	July 15, 2010	$0.14
		$0.42

Tax information and historical distributions are available on our website.