

Quarterly Report

THREE AND SIX MONTHS ENDED JUNE 30, 2009

Freehold Royalty Trust Announces
2009 Second Quarter Results and
20% Increase in Monthly Distributions

RESULTS AT A GLANCE Financial (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2009	2008	Change	2009	2008	Change
Gross revenue	29,164	61,301	-52%	55,782	109,875	-49%
Net income	6,776	36,163	-81%	9,167	59,810	-85%
Per Trust Unit, basic and diluted (\$)	0.14	0.73	-81%	0.19	1.21	-84%
Cash provided by operating activities	21,938	46,379	-53%	43,507	80,200	-46%
Per Trust Unit (\$)	0.44	0.94	-53%	0.88	1.63	-46%
Funds generated from operations (1)	21,833	53,183	-59%	40,452	92,365	-56%
Per Trust Unit (\$)	0.44	1.08	-59%	0.82	1.87	-56%
Capital expenditures	1,661	2,135	-22%	3,688	4,337	-15%
Distributions declared	14,852	30,114	-51%	29,693	52,312	-43%
Per Trust Unit (\$) (2)	0.30	0.61	-51%	0.60	1.06	-43%
Long-term debt, period end	156,000	151,000	3%	156,000	151,000	3%
Unitholders' equity, period end	200,561	260,250	-23%	200,561	260,250	-23%
Trust Units (000s) (3)	49,495	49,353	0%	49,478	49,335	0%
Operating (per boe) (4)						
Average daily production (boe/d)	7,295	7,674	-5%	7,408	7,914	-6%
Average price realizations (\$)	42.99	86.43	-50%	40.39	74.96	-46%
Operating netback (\$) (1)	37.56	81.21	-54%	35.32	69.86	-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)".

MONTHLY DISTRIBUTION INCREASED

With oil prices and heavy oil differentials tracking better than our earlier forecast, we are increasing monthly distributions by 20% to \$0.12 per Trust Unit. The Board of Directors has declared the August distribution of \$0.12 per Trust Unit, which will be paid on September 15, 2009 to Unitholders of record on August 31, 2009 (ex-distribution date August 27, 2009). Including this payment, our 12-month trailing cash distributions total \$2.17 per Trust Unit.

Message to Unitholders

The first half of 2009 has been challenging for the oil and gas industry in western Canada, as weak commodity markets continue to affect producers' cash flows and dampen activity levels.

Overall, our results for the year to date reflect lower selling prices due to the steep decline in commodity prices compared with last year. Cash provided by operating activities and net income declined significantly due to lower revenues. Our average price realizations declined 50% in the second quarter, while our production, which remains unhedged, was down 5%. Distributions, which were lowered in January 2009 in anticipation of lower commodity prices, were maintained at \$0.10 per month.

WTI crude oil prices rose in the second quarter from the lows seen earlier in the year, although the benefit was partly offset by the rise of the Canadian dollar. Freehold also benefited from exceptionally narrow heavy oil price differentials, due to the growing acceptance of heavier crude by North American refiners and high seasonal demand. However, the differential is expected to widen after the peak summer asphalt paving season ends.

With supplies high and demand low, natural gas prices have fallen to 10-year lows (trading recently below \$3.00 per thousand cubic feet), causing marginal production to be shut-in and natural gas directed drilling to be curtailed. We believe that lower reinvestment will reduce supply and lead to an eventual price recovery, but the timing of such a recovery remains uncertain. Natural gas in storage, in preparation for winter heating demand, is currently well above the five-year average. In this environment, we are fortunate to have an oil-weighted portfolio.

As anticipated, drilling on our royalty lands reflected the overall decline in industry activity levels. As at June 30, 2009, there were 43 licensed drilling locations on our royalty lands, down from 95 locations at the same time last year. Second quarter drilling on working interest properties was also significantly lower than last year, as our major capital projects were deferred to the second half of 2009. Four (0.4 net) horizontal oil wells were recently drilled at Pembina Cardium Unit #9; these wells will be stimulated using multi-stage fracture technology, with production commencing in the third quarter. Our plans for the balance of the year include two (2.0 net) Bakken oil wells in Southeast Saskatchewan and 11 (2.6 net) Dina oil wells at Hayter, Alberta. Based on reduced activity and delayed projects, our production forecast for the year has been reduced from 7,500 boe per day to 7,300 boe per day (5,095 boe per day of royalty production and 2,205 boe per day of working interest production).

The Alberta Government's short-term stimulus plan to encourage conventional oil and natural gas activity in the province was recently extended for an additional year. All new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2011 qualify for drilling credits and Crown royalty reductions. The stimulus plan is expected to have a positive impact on industry activity levels in the coming months, although producers may delay initial production (particularly for natural gas wells) until prices improve.

Although access to credit and capital markets moderately improved in the second quarter, capital investment programs continue to be funded primarily from cash flows. As some producers look to sell non-core oil and gas assets to fund their core exploration and development programs or reduce debt, we believe there may be opportunities for us to acquire additional royalty interests.

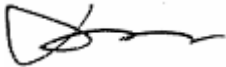
With oil prices and heavy oil differentials tracking better than our earlier forecast (see discussion of key operating assumptions on page 6), we are increasing monthly distributions by 20% to \$0.12 per Trust Unit, commencing with the September 15, 2009 payment. Excluding any potential acquisitions, we anticipate reducing long-term debt to \$155 million by year end. We will continue to review our distributions policy monthly and make adjustments, if necessary, to ensure that cash distributions are in line with cash flow.

In light of the federal government's plan to impose a tax on distributions from certain publicly-traded investment flow-through (SIFT) entities beginning in 2011, many trusts have announced plans to convert to a corporation and some have already done so. However, our current limited ability to generate tax pools make this alternative a less obvious choice for Freehold than it is for many of our peers. Our Corporate SIFT Tax Strategy Committee, which has a mandate to determine the best course of action for Freehold, continues to deliberate. We anticipate a timely recommendation from the committee.

Bill Siebens, Chairman of Freehold Resources since the Trust's inception, retired in May. We were fortunate to have had Bill's guidance and support for the past 12½ years, benefiting from his knowledge of our royalty assets, which were at one time owned by Siebens Oil and Gas. Nolan Blades succeeds Bill as Chair of the Board. Nolan has been an independent director of Freehold since 1996 and previously headed up our Audit and Reserves Committees.

In closing, I would like to take this opportunity to acknowledge the management and staff of Rife Resources, who do an excellent job of managing the assets of Freehold on behalf of the Unitholders. That we have highly skilled people, with very little staff turnover, is a testament to the leadership of my predecessor, David Sandmeyer. David retired as President and CEO in May but remains on the Board of Freehold Resources; I look forward to his continued guidance.

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, 2009 and previous periods, and the outlook for Freehold based on information available as at August 12, 2009. The financial information contained herein has been 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, 2009 and June 30, 2008, 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, 2008 and 2007, together with the accompanying notes.

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 MD&A offers our assessment of Freehold's future plans and operations as at August 12, 2009, and contains forward-looking statements including our expectations for production, commodity prices, activity levels and acquisition opportunities referred to in the Message to Unitholders; Future Income Tax; and our expectations for production, commodity prices, reduced natural gas supply, activity levels, key operating assumptions and acquisition opportunities referred to under Business Environment. These forward-looking statements are provided to allow readers to better understand our business and prospects.

Such statements are generally identified by the use of words such as "anticipate", "continue", "estimate", "expect", "forecast", "may", "will", "project", "should", "plan", "intend", "believe", and similar expressions (including the negatives thereof). By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, taxation, royalties, regulation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. Risks are described in more detail in our AIF.

With respect to forward-looking statements contained in this 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; 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 acquisitions and our 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 the MD&A 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 12 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.

Business Environment

The first six months of 2009 were challenging for the oil and gas industry in western Canada, as weak commodity markets continued to affect producers' cash flows and dampen activity levels. WTI crude oil prices rose in the second quarter from the lows seen earlier in the year, although the benefit was partly offset by the rise of the Canadian dollar. Freehold also benefited from exceptionally narrow heavy oil differentials, due to the growing acceptance of heavier crude by North American refiners and high seasonal demand. However, the differential is expected to widen after the peak summer asphalt paving season ends.

Natural gas markets continue to be weighed down by the over supply situation in North America. The economic downturn has reduced industrial demand for energy. Natural gas in storage, in preparation for winter heating demand, is currently well above the five-year average. With supplies high and demand low, natural gas prices have fallen to 10-year lows (trading recently below \$3.00 per thousand cubic feet), causing marginal production to be shut-in and natural gas directed drilling to be curtailed. On July 7, 2009, the Canadian Association of Oilwell Drilling Contractors again downgraded its outlook, estimating that 2009 drilling activity will be down 60% from 2008 levels. We believe that lower reinvestment will reduce natural gas supply and lead to an eventual price recovery, but the timing of such a recovery remains uncertain.

The Alberta Government’s short-term stimulus plan to encourage conventional oil and natural gas activity in the province was recently extended for an additional year. All new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2011 qualify for drilling credits and Crown royalty reductions. The stimulus plan is expected to have a positive impact on industry activity levels in the coming months, although producers may delay initial production (particularly for natural gas wells) until prices improve.

Although access to credit and capital markets has moderately improved in recent months, capital investment programs continue to be funded primarily from cash flows. As some producers look to sell non-core oil and gas assets to fund their core exploration and development programs or reduce debt, we believe there may be opportunities for us to acquire additional royalty interests.

DISTRIBUTION POLICY

With oil prices and heavy oil differentials tracking better than our earlier forecast, we are increasing monthly distributions by 20% to \$0.12 per Trust Unit, commencing with the September 15, 2009 payment. We will continue to review our distributions policy monthly and make adjustments, if necessary, to ensure that cash distributions are in line with cash flow.

Our key operating assumptions are outlined in the table below. A sensitivity analysis of the potential impact of key variables on distributions to Unitholders is provided on page 40 of our 2008 annual report. Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices, 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 about one-third of our total boe production is heavy oil.

2009 KEY OPERATING ASSUMPTIONS	August 12 2009	May 13 2009
Average daily production (boe/d)	7,300	7,500
Average WTI oil price (US\$/bbl)	60.00	44.00
Average AECO natural gas price (Cdn\$/Mcf)	3.70	5.00
Average exchange rate (Cdn\$/US\$)	0.87	0.80
Average operating costs (\$/boe)	4.10	4.10
Average G&A costs (1)	2.90	2.90
Capital expenditures (\$ millions)	12.0	12.0
Long-term debt at year end (\$ millions)	155.0	159.0
Weighted average Trust Units outstanding (thousands)	49,521	49,514
Estimated portion of distributions taxable as income (%)	90-100%	90-100%

(1) Excludes unit based compensation.

We have lowered our 2009 production estimate by approximately 3%. The reduction relates primarily to working interest properties where we deferred drilling and optimization of new wells until the second half of 2009. Four (0.4 net) horizontal oil wells were recently drilled at Pembina Cardium Unit #9; these wells will be stimulated using multi-stage fracture technology, with production commencing in the third quarter. Our plans for the balance of the year include two (2.0 net) Bakken oil wells in Southeast Saskatchewan and 11 (2.6 net) Dina oil wells at Hayter, Alberta. Based on reduced activity and delayed projects, our production for the year is forecast to average 7,300 boe per day (5,095 boe per day of royalty production and 2,205 boe per day of working interest production).

We have adjusted our commodity price and foreign exchange assumptions to reflect actual results for the first six months of 2009 and current market expectations for the remainder of the year. As a result of higher than anticipated oil prices (and excluding any potential acquisitions), we anticipate reducing long-term debt to \$155 million by year end. We have not adjusted our operating cost assumptions as cost savings in the second half of 2009 are expected to offset higher costs recorded for the first half.

CORPORATE SIFT TAX STRATEGY COMMITTEE UPDATE

In light of the federal government’s plan to impose a tax on distributions from certain publicly-traded investment flow-through (SIFT) entities beginning in 2011, many trusts have announced plans to convert to a corporation and some have already done so. However, our current limited ability to generate tax pools make this alternative a less obvious choice for Freehold than it is for many of our peers. Our Corporate SIFT Tax Strategy Committee, which has a mandate to determine the best course of action for Freehold, continues to deliberate. We anticipate a timely recommendation from the committee.

Development Activities

Weaker drilling economics led to a sharp decline in industry drilling activity, which was further exacerbated by an early spring break-up. Industry activity in the second quarter of 2009 was down 52%, as producers pared back their capital spending in light of lower commodity prices and reduced cash flows. According to statistics published by the Canadian Association of Oilwell Drilling Contractors, just over 1,500 wells were drilled in western Canada in the second quarter of 2009 compared with more than 3,100 last year.

As anticipated, drilling on our royalty lands reflected the overall decline in industry activity levels. As at June 30, 2009, there were 43 licensed drilling locations on our royalty lands, down from 95 locations at the same time last year.

DRILLING ON ROYALTY LANDS	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2009	2008	Change	2009	2008	Change
Unitized wells						
Gross	92	51	80%	219	170	29%
Equivalent net (1)	0.2	0.2	0%	0.9	0.7	29%
Non-unitized wells						
Gross	8	40	-80%	66	151	-56%
Equivalent net (1)	0.4	1.3	-69%	2.7	6.3	-57%
Total						
Gross	100	91	10%	285	321	-11%
Equivalent net (1)	0.6	1.5	-60%	3.6	7.0	-49%

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

Second quarter drilling on working interest properties was also significantly lower than last year, as our major capital projects were deferred to the second half of 2009. We participated in the drilling of one (0.1 net) well in Saskatchewan and one (0.1 net) well in Alberta, with a 100% net success rate.

DRILLING ON WORKING INTEREST PROPERTIES	Three Months Ended June 30				Six Months Ended June 30			
	2009		2008		2009		2008	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	2	0.2	10	2.2	6	0.7	14	2.7
Natural gas	-	-	-	-	1	-	7	0.2
Other	-	-	1	0.2	-	-	2	0.3
Total	2	0.2	11	2.4	7	0.7	23	3.2

Quarterly Performance and Trends

Our 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.

The following significant changes have occurred over the last eight quarters that have influenced our financial results.

- WTI crude oil prices have exhibited significant volatility in the last eight quarters. 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 but began to recover in the second quarter.
- Fluctuations in U.S. to Canadian dollar exchange rates also affect our oil price realizations. Over the past eight quarters, exchange rate volatility has resulted in both positive and negative effects on our Canadian dollar oil revenues relative to the benchmark WTI, which is referenced in U.S. dollars.
- Demand for Canadian heavy crude has strengthened in recent years as new pipelines added in 2006 have given producers in western Canada better access to U.S. markets. In addition, many North American refineries have been retooled to process heavier grades of crude. As a result, heavy oil differentials have narrowed significantly from historical levels. Demand for heavy oil is typically highest during the summer paving season.
- AECO natural gas prices have also exhibited significant volatility. Natural gas markets strengthened briefly in mid-2008; however, with supply continuing to outstrip demand, prices have faced downward pressure for the past nine months, falling to 10-year lows during the second quarter of 2009. Natural gas is a typically seasonal, weather-dependent fuel. Demand for natural gas is generally higher during the winter (for heating) and summer (for cooling), and lower during the spring and fall.
- We have 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. In January 2009, we lowered the rate to \$0.10 per Trust Unit to preserve operating stability and financial flexibility through the current period of low commodity prices. This rate was maintained through the second quarter of 2009.
- In the third quarter of 2007, we acquired various gross overriding royalty (GORR) interests on approximately 319,000 gross acres of land in Alberta and Saskatchewan for \$90.4 million. These acquisitions were funded through our credit facilities, which were increased to \$210 million in the third quarter of 2007. On July 7, 2008, we acquired certain royalty and minor working interests in Alberta for \$8.5 million.
- In 2007 and 2008, the oil and gas industry experienced rising costs as strong economic growth created high demand for people and services. These inflationary pressures began to ease in late 2008 as the economic downturn and weak commodity prices curtailed industry activity levels.
- 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.

QUARTERLY REVIEW	2009		2008				2007	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial (\$000s, except as noted)								
Revenue, net of royalty expense	28,516	25,315	33,174	58,210	59,563	46,553	39,218	36,086
Distributions declared	14,852	14,841	54,387	37,050	30,114	22,198	28,096	22,165
Per Trust Unit (\$) (1) (2)	0.30	0.30	1.10	0.75	0.61	0.45	0.57	0.45
Net income (loss)	6,776	2,391	13,374	36,772	36,163	23,647	19,067	12,487
Per Trust Unit, basic and diluted (\$)	0.14	0.05	0.27	0.74	0.73	0.48	0.39	0.25
Cash provided by operating activities	21,938	21,569	41,672	57,380	46,379	33,821	32,503	29,796
Per Trust Unit (\$)	0.44	0.44	0.84	1.16	0.94	0.69	0.66	0.61
Funds generated from operations (3)	21,833	18,619	26,942	51,977	53,183	39,182	32,591	29,907
Per Trust Unit (\$)	0.44	0.38	0.55	1.05	1.08	0.79	0.66	0.61
Property and royalty acquisitions	-	-	(782)	8,475	-	-	26	90,430
Capital expenditures	1,661	2,027	3,770	9,222	2,135	2,202	3,901	1,960
Long-term debt	156,000	160,000	140,000	141,000	151,000	169,000	178,000	179,000
Trust Units outstanding								
Weighted average (000s)	49,495	49,460	49,424	49,389	49,353	49,317	49,282	49,246
At quarter end (000s)	49,531	49,495	49,459	49,424	49,388	49,352	49,317	49,281
Operating (\$/boe, except as noted)								
Daily production (boe/d)	7,295	7,522	7,779	7,613	7,674	8,152	8,591	8,219
Royalty interest production (%)	71	70	71	71	72	71	70	69
Average selling price	42.99	37.85	46.55	83.47	86.43	64.16	50.57	48.28
Operating netback (2)	37.56	33.13	42.14	79.14	81.21	59.18	46.47	43.65
Operating expenses	5.39	4.27	4.21	3.97	4.08	3.58	3.14	4.07
Working interest properties	18.78	14.27	14.31	13.51	14.37	12.54	10.56	13.17
General and administrative expenses	2.12	3.98	2.20	1.95	2.15	3.16	1.80	1.28
Benchmark Prices								
WTI crude oil (US\$/bbl)	59.62	43.08	58.69	117.98	123.98	97.86	90.68	75.38
Exchange rate (Cdn\$/US\$)	0.86	0.80	0.83	0.96	0.99	1.00	1.02	0.96
Edmonton Par crude oil (Cdn\$)	65.90	49.66	63.21	121.85	126.07	97.50	86.42	79.95
Light/heavy oil differential (Cdn\$/bbl)	3.54	5.25	13.72	16.43	21.43	19.47	29.37	23.95
Bow River/Hardisty (Cdn\$/bbl)	62.36	44.41	49.49	105.42	104.64	78.04	57.05	56.00
AECO natural gas (Cdn\$/Mcf)	3.66	5.62	6.78	9.24	9.35	7.13	6.00	5.61
Unit Trading Performance								
High (\$)	15.18	11.76	18.43	24.35	24.40	19.29	15.85	15.85
Low (\$)	8.70	6.87	9.15	16.01	17.51	14.55	14.46	12.51
Close (\$)	13.85	8.90	10.49	17.10	23.99	18.04	15.60	15.26
Volume (000s)	8,756	9,310	10,474	10,263	8,993	6,740	7,036	5,172

(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 (\$0.35 per Trust Unit in 2008 and \$0.12 per Trust Unit in 2007).

(3) See Non-GAAP Measures.

Results of Operations

Overall, our results for the second quarter of 2009 reflect lower production and lower selling prices due to the steep decline in commodity prices compared with last year. Cash provided by operating activities and net income declined significantly due to lower revenues.

FUNDS GENERATED FROM OPERATIONS AND NET INCOME (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2009	2008	Change	2009	2008	Change
	Cash provided by operating activities	21,938	46,379	-53%	43,507	80,200
Changes in non-cash working capital	(105)	6,804	-102%	(3,055)	12,165	-155%
Funds generated from operations	21,833	53,183	-59%	40,452	92,365	-52%
Per Trust Unit (\$)	0.44	1.08	-59%	0.82	1.87	-52%
Net income	6,776	36,163	-81%	9,167	59,810	-90%
Per Trust Unit, basic and diluted (\$)	0.14	0.73	-81%	0.19	1.21	-90%

PRODUCTION

On a boe basis, our production was down 5% in the second quarter, as drilling activity was insufficient to offset natural production declines. Royalty interests contributed 71% (2008 Q2 – 72%) of total volumes produced. Our production mix for the first six months of 2009 was approximately 37% natural gas and 63% liquids (32% heavy oil, 27% light and medium oil, and 4% NGL).

AVERAGE DAILY PRODUCTION	Three Months Ended June 30			Six Months Ended June 30		
	2009	2008	Change	2009	2008	Change
Royalty lands						
Oil (bbls/d)	2,824	2,893	-2%	2,829	3,014	-6%
NGL (bbls/d)	265	234	13%	271	232	17%
Natural gas (Mcf/d)	12,671	14,211	-11%	12,822	14,481	-11%
Oil equivalent (boe/d)	5,201	5,496	-5%	5,237	5,660	-7%
Working interest properties						
Oil (bbls/d)	1,446	1,506	-4%	1,545	1,635	-6%
NGL (bbls/d)	70	73	-4%	68	71	-4%
Natural gas (Mcf/d)	3,465	3,595	-4%	3,346	3,289	2%
Oil equivalent (boe/d)	2,094	2,178	-4%	2,171	2,254	-4%
Total Trust						
Oil (bbls/d)	4,270	4,399	-3%	4,374	4,649	-6%
NGL (bbls/d)	335	307	9%	339	303	12%
Natural gas (Mcf/d)	16,136	17,806	-9%	16,168	17,770	-9%
Oil equivalent (boe/d)	7,295	7,674	-5%	7,408	7,914	-6%
Number of days in period (days)	91	91	0%	181	182	-1%
Total volumes during period (Mboe)	664	698	-5%	1,341	1,440	-7%

MARKETING AND HEDGING

As at June 30, 2009, approximately 45% of our royalty oil production was being marketed by Freehold using 30-day contracts. We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. Approximately 14% 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 (86%) is marketed with the operators' production.

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

COMMODITY PRICES

The following table is a summary of average benchmark prices for the second quarter. As approximately one-third of our total boe production is heavy oil, the markets for heavy oil are of particular relevance for us. As noted above, heavy oil differentials have narrowed significantly as a result of improved transportation routes, strong refinery demand for this product type, and high seasonal demand. In the table below, we have included Western Canada Select (WCS) as a new benchmark crude. WCS resembles Bow River crude and 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 BENCHMARK PRICES (1)	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2009	2008	Change	2009	2008	Change
WTI crude oil (US\$/bbl)	59.62	123.98	-52%	51.35	110.94	-54%
US\$/Cdn\$ exchange rate	0.8579	0.9901	-13%	0.8305	0.9931	-16%
Edmonton Par crude oil (Cdn\$/bbl)	65.90	126.07	-48%	57.78	111.79	-48%
Bow River/Hardisty (Cdn\$/bbl)	62.36	104.64	-40%	53.38	91.34	-42%
Western Canada Select/Hardisty (Cdn\$/bbl)	60.71	103.32	-41%	51.62	90.01	-43%
AECO natural gas (Cdn\$/Mcf)	3.66	9.35	-61%	4.64	8.24	-44%

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

Our average selling prices reflect product quality and transportation differences from benchmark prices. Due to extremely low natural gas prices in 2009, processing fees, which are netted from the royalty payments, made up a larger proportion of price, reducing our natural gas price realizations.

AVERAGE SELLING PRICES	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2009	2008	Change	2009	2008	Change
Oil (\$/bbl)	59.07	105.63	-44%	50.08	89.62	-44%
NGL (\$/bbl)	37.41	81.17	-54%	39.09	74.40	-47%
Oil and NGL (\$/bbl)	57.50	104.04	-45%	49.29	88.68	-44%
Natural gas (\$/Mcf)	3.02	9.75	-69%	4.14	8.67	-52%
Oil equivalent (\$/boe)	42.99	86.43	-50%	40.39	74.96	-46%

Revenue

Gross revenue declined 52% in the second quarter of 2009, due to significantly lower realized prices and, to a lesser extent, lower production. The accompanying table demonstrates the net effect of price and volume variances on gross revenues.

GROSS REVENUE VARIANCES (\$000s)	Three Months Ended June 30		Six Months Ended June 30	
	2009 vs. 2008	2008 vs. 2007	2009 vs. 2008	2008 vs. 2007
Oil and NGL				
Production decrease	(530)	(3,745)	(2,371)	(5,404)
Price increase (decrease)	(19,932)	24,163	(35,501)	36,744
Net increase (decrease)	(20,462)	20,418	(37,872)	31,340
Natural gas				
Production decrease	(460)	(2,642)	(1,273)	(2,556)
Price increase (decrease)	(10,901)	5,006	(14,650)	5,062
Net increase (decrease)	(11,361)	2,364	(15,923)	2,506
Other (1)	(314)	504	(298)	1,009
Gross revenue increase (decrease)	(32,137)	23,286	(54,093)	34,855

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

Expenses

ROYALTY EXPENSE AND MINERAL TAX

Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties. Annual mineral tax is payable to the Crown in the first quarter of the year. Crown royalty rates, which are tied to commodity prices and production volumes, were significantly lower in the first and second quarters of 2009, due to the steep decline in commodity prices and, to a lesser extent, lower production compared with last year.

ROYALTY EXPENSE AND MINERAL TAX (1) (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2009	2008	Change	2009	2008	Change
Working interest properties						
Crown royalties	356	1,395	-74%	820	2,490	-67%
Third party royalties	179	235	-24%	343	564	-39%
Mineral tax	108	87	24%	256	215	19%
Working interest properties	643	1,717	-63%	1,419	3,269	-57%
Per boe (\$)	3.37	8.66	-61%	3.61	7.97	-55%
Royalty lands						
Crown royalties	-	-	-	-	-	-
Third party royalties	-	-	-	-	-	-
Mineral tax	5	21	-76%	532	490	9%
Royalty lands	5	21	-76%	532	490	9%
Per boe (\$)	0.01	0.04	-75%	0.56	0.48	17%
Total Trust	648	1,738	-63%	1,951	3,759	-48%
Per boe (\$)	0.98	2.49	-61%	1.46	2.61	-44%

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

OPERATING EXPENSES

Operating expenses in the second quarter of 2009 included approximately \$800,000 (\$1.21 per boe) of expenses relating to 2005 to 2008. Excluding this one-time adjustment, operating costs on our working interest properties were consistent with the second quarter last year.

OPERATING EXPENSES	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2009	2008	Change	2009	2008	Change
Working interest properties (\$000s)	3,578	2,849	26%	6,468	5,506	17%
Per boe (\$)	18.78	14.37	31%	16.46	13.42	23%
Royalty lands (\$000s) (1)	-	-	-	-	-	-
Per boe (\$)	-	-	-	-	-	-
Total operating expenses (\$000s)	3,578	2,849	26%	6,468	5,506	17%
Total Trust (\$/boe)	5.39	4.08	32%	4.82	3.82	26%

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

OPERATING NETBACK

We manage one of the largest portfolios of oil and gas royalties in Canada. Our royalty lands are comprised of a large and widely diversified portfolio of properties extending 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, production from which yields higher operating netbacks than our working interest properties.

NETBACK ANALYSIS	Six months ended June 30, 2009		
	Royalty Interest	Working Interest	Total Trust
	Lands	Properties	
(\$000s)			
Gross revenue (1)	38,551	17,232	55,782
Royalty expense and mineral tax (2)	(532)	(1,419)	(1,951)
Net revenue	38,019	15,813	53,831
Operating expense	-	(6,468)	(6,468)
Operating netback	38,019	9,345	47,363

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

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

Our operating netback per boe for the first and second quarters of 2009 declined significantly, due to lower commodity prices, lower production, and higher operating expenses, partly offset by lower royalty expense and mineral tax.

OPERATING NETBACK	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2009	2008	Change	2009	2008	Change
(\$/boe)						
Gross revenue (1)	43.93	87.78	-50%	41.60	76.29	-45%
Royalty expense and mineral tax (2)	(0.98)	(2.49)	-61%	(1.46)	(2.61)	-44%
Operating expenses	(5.39)	(4.08)	32%	(4.82)	(3.82)	26%
Operating netback	37.56	81.21	-54%	35.32	69.86	-49%

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

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

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

G&A expenses include direct costs incurred by the Trust and reimbursement of the G&A expenses incurred by the Manager on behalf of the Trust. G&A expenses in the second quarter included \$1.2 million charged by the Manager for time and direct costs incurred on behalf of the Trust.

G&A EXPENSES	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2009	2008	Change	2009	2008	Change
G&A expenses (\$000s)	1,404	1,504	-7%	4,098	3,847	7%
Per boe (\$)	2.12	2.15	-1%	3.06	2.67	15%
As a percentage of revenue	5%	2%	150%	7%	4%	75%

UNIT BASED COMPENSATION

Manager's Long-Term Incentive Plan (LTIP)

Employees of the Manager receive cash compensation in relation to the value of a specified number of notional units after a three-year vesting period. 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.

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 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.

UNIT BASED COMPENSATION	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2009	2008	Change	2009	2008	Change
Manager's long-term incentive plan	844	1,324	-36%	883	1,675	-47%
Deferred trust unit plan	21	41	-49%	271	238	14%
Unit based compensation	865	1,365	-37%	1,154	1,913	-40%
Per boe (\$)	1.30	1.95	-33%	0.86	1.33	-35%
As a percentage of revenue	3%	2%	50%	2%	2%	0%

INTEREST AND FINANCING

Interest expense declined 13% in the second quarter of 2009. The decrease was attributable to lower borrowing costs due to the reduction in lending rates and slightly lower debt levels compared with the second quarter last year, partly offset by rollover fees related to the annual renewal of our credit facilities in May.

INTEREST AND FINANCING	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2009	2008	Change	2009	2008	Change
Interest expense (000s)	1,550	1,788	-13%	2,416	4,000	-40%
Per boe (\$)	2.34	2.56	-9%	1.80	2.78	-35%

DEPLETION AND DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION

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.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSES (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2009	2008	Change	2009	2008	Change
	Depletion and depreciation	15,764	17,006	-7%	31,640	34,579
Accretion of asset retirement obligation	82	96	-15%	163	191	-15%
Total depletion, depreciation and accretion expenses	15,846	17,102	-7%	31,803	34,770	-9%
Per boe (\$)	23.87	24.49	-3%	23.72	24.14	-2%

MANAGEMENT FEES

The quarterly management fee, which is paid in Trust Units, was 35,654 Trust Units for the first and second quarters of 2009, unchanged from 2008. The ascribed value was lower in 2009 because of lower closing Trust Unit prices at the end of each quarter.

MANAGEMENT FEES (Paid in Trust Units)	Three Months Ended June 30			Six Months Ended June 30		
	2009	2008	Change	2009	2008	Change
	Trust Units issued in payment of management fees	35,654	35,654	0%	71,308	71,308
Ascribed value (\$000s) (1)	494	855	-42%	811	1,498	-46%
Per boe (\$)	0.74	1.22	-39%	0.60	1.04	-42%

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

FUTURE INCOME TAX

On March 4, 2009, changes to the SIFT tax rules were deemed substantively enacted under Canadian GAAP. The provincial component of the SIFT tax applicable to Freehold will be reduced from 13% to 10%, resulting in a combined SIFT tax rate in 2011 of 26.5%, and 25.0% thereafter. As a result, we recorded a \$0.2 million recovery in future income tax in the first quarter and a further \$2.1 million recovery in the second quarter.

Liquidity and Capital Resources

CAPITAL EXPENDITURES

Our capital expenditure obligations (with respect to our working interest properties) are deducted from funds generated from operations prior to the determination of distributions to Unitholders. Capital expenditures on working interest properties totalled \$1.7 million in the second quarter of 2009 (\$3.7 million for the year to date). We have no capital requirements with respect to our royalty properties.

ACQUISITIONS AND CAPITAL EXPENDITURES (\$000s, except as noted)	Three Months Ended June 30			Six Months Ended June 30		
	2009	2008	Change	2009	2008	Change
	Capital expenditures	1,661	2,135	-22%	3,688	4,337
Change in reclamation fund	100	(9)	-1211%	192	81	137%
	1,761	2,126	-17%	3,880	4,418	-12%

WORKING CAPITAL

The following table shows the changes in working capital during the past four quarters. 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 prices changes during the period.

COMPONENTS OF WORKING CAPITAL (\$000s)	June 30 2009	Mar. 31 2009	Dec. 31 2008	Sept. 30 2008	June 30 2008
Cash	369	546	537	212	521
Current portion of deferred compensation	-	34	-	38	194
Accounts receivable	21,315	21,870	23,261	38,507	42,538
Current assets	21,684	22,450	23,798	38,757	43,253
Distributions declared	(4,953)	(4,950)	(29,676)	(12,356)	(12,347)
Current portion of unit based compensation	(743)	(131)	(83)	(452)	(1,166)
Accounts payable and accrued liabilities	(13,824)	(15,780)	(14,094)	(14,830)	(11,708)
Current liabilities	(19,520)	(20,861)	(43,853)	(27,638)	(25,221)
Working capital (1)	2,164	1,589	(20,055)	11,119	18,032

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

DEBT ANALYSIS

At the end of the second quarter, we had \$54 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 latest review process was completed in May 2009 with no changes to our \$210 million borrowing base.

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.

DEBT ANALYSIS (\$000s)	As at June 30	As at December 31	Change
	2009	2008	
Long-term debt	156,000	140,000	11%
Short-term debt	-	-	-
Total debt	156,000	140,000	11%
Less: working capital	2,164	(20,055)	-111%
Net debt obligations	153,836	160,055	-4%

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, 2009, the Trust was in compliance with all such covenants.

FINANCIAL LEVERAGE AND COVERAGE RATIOS (1)	As at June 30	As at December 31	Change
	2009	2008	
Net debt to funds generated from operations (times)	1.3	0.9	44%
Net debt to distributions (times)	1.3	1.1	18%
Distributions to interest expense (times)	22.2	20.4	9%
Net debt to net debt plus equity (%)	43%	42%	2%

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

DISTRIBUTIONS

Distributions in the second quarter totalled \$0.30 per Trust Unit. From inception to June 30, 2009, the Trust has distributed \$754.1 million (\$19.73 per Trust Unit) to Unitholders.

ACCUMULATED DISTRIBUTIONS	Three Months Ended		Six Months Ended	
	June 30		June 30	
	2009	2008	2009	2008
Distributions declared (\$000s)	14,852	30,114	29,693	52,312
Accumulated, beginning of period	739,259	602,867	724,418	580,669
Accumulated, end of period	754,111	632,981	754,111	632,981
Distributions per Trust Unit (\$) (1)	0.30	0.61	0.60	1.06
Accumulated, beginning of period	19.43	16.67	19.13	16.22
Accumulated, end of period	19.73	17.28	19.73	17.28

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

The following table 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 repay bank debt as required. Net income includes significant non-cash charges that do not affect cash flow. These charges amounted to \$15.1 million for the second quarter of 2009 (2008 – \$17.2 million) and \$31.4 million for the first half of 2009 (2008 – \$32.8 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.

DISTRIBUTION ANALYSIS	Three Months Ended		Six Months Ended	
	June 30		June 30	
(\$000s)	2009	2008	2009	2008
Cash provided by operating activities	21,938	46,379	43,507	80,200
Net income	6,776	36,163	9,167	59,810
Distributions declared	14,852	30,114	29,693	52,312
Excess of cash provided by operating activities over distributions declared	48%	54%	47%	53%
Excess (shortfall) of net income over distributions declared	(54%)	20%	(69%)	14%

UNITHOLDERS' CAPITAL

As at June 30, 2009, there were 49,530,737 Trust Units outstanding and as at August 12, 2009, there were 49,546,164 Trust Units outstanding. Following his retirement from the Board in the second quarter, William Siebens redeemed 22,038 deferred trust units and was issued 15,427 Trust Units from treasury. As at June 30, 2009, there were 68,262 deferred trust units outstanding and at August 12, 2009, there were 48,328 deferred trust units outstanding. On August 12, 2009, 1,272 deferred trust units were granted to Nolan Blades, who became Chair of the Board in May, and 954 deferred trust units were granted to David Sandmeyer, who became an eligible director in July.

TRUST UNITS OUTSTANDING	Three Months Ended			Six Months Ended		
	June 30			June 30		
	2009	2008	Change	2009	2008	Change
Weighted average						
Basic	49,495,475	49,352,859	0%	49,477,748	49,335,032	0%
Diluted	49,564,608	49,394,038	0%	49,545,749	49,376,726	0%
At period end	49,530,737	49,388,121	0%	49,530,737	49,388,121	0%

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 2008 annual MD&A, we are continuing to assess the impact of adopting IFRS effective January 1, 2011. We have assigned internal staff to lead the conversion project. We have also retained an external advisor to assist us, and are involving our auditors in the process. Our transition plan addresses resources required, employee training, continued analysis of key accounting standard differences, evaluation of information system requirements, and an impact assessment on operations, internal controls over financial reporting, and disclosures.

Through a business impact study, we have identified and are focusing our efforts on the high and medium impact areas. These areas include the classification of royalty interests as tangible (IAS 16) or intangible (IAS 38) assets, the determination of appropriate cash generating units for royalty and working interests, and options for transitioning from full cost accounting for petroleum and natural gas operations, including the first-time adoption elections.

Throughout the year, we will provide IFRS conversion progress updates as additional information becomes available.

FINANCIAL INSTRUMENTS – DISCLOSURES

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, “*Financial Instruments – Disclosures*”, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust on December 31, 2009.

Related Party Transactions

We do not operate any of our oil and gas assets, nor do we 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 costs (see General and Administrative Expenses and Unit Based Compensation) and receives a quarterly management fee paid in Trust Units (see Management Fees).

Contingencies

In the second quarter of 2009, a statement of claim was filed against the Trust in the amount of \$9.0 million. The claim involves disputed land interests and royalty obligations. After receiving outside legal advice, the Trust has assessed the claim, believes it has no merit, and intends to aggressively defend itself in the claim. The outcome is not determinable; therefore no amounts have been recorded in the financial statements.

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, 2009. 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.

Consolidated Balance Sheets

(\$000s) (unaudited)	June 30 2009	December 31 2008
Assets		
Current assets:		
Cash	\$ 369	\$ 537
Accounts receivable	21,315	23,261
	21,684	23,798
Reclamation fund	2,019	1,827
Deferred compensation (note 4)	1,682	120
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$481,719 (2008 - \$450,079)	398,603	426,530
	\$ 423,988	\$ 452,275
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	\$ 4,953	\$ 29,676
Accounts payable and accrued liabilities	13,824	14,094
Current portion of unit based compensation (note 4)	743	83
	19,520	43,853
Asset retirement obligation	5,736	5,663
Unit based compensation payable (note 4)	1,947	243
Long-term debt (note 2)	156,000	140,000
Future income tax liability	40,224	42,511
Unitholders' equity:		
Unitholders' capital (note 3)	568,121	567,310
Contributed Surplus (note 4)	993	722
Deficit	(368,553)	(348,027)
	200,561	220,005
	\$ 423,988	\$ 452,275

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		Six Months Ended June 30	
	2009	2008	2009	2008
Revenue:				
Royalty income and working interest sales	\$ 29,164	\$ 61,301	\$ 55,782	\$ 109,875
Royalty expense and mineral tax	(648)	(1,738)	(1,951)	(3,759)
	28,516	59,563	53,831	106,116
Expenses:				
Operating	3,578	2,849	6,468	5,506
General and administrative	1,404	1,504	4,098	3,847
Unit based compensation (note 4)	865	1,365	1,154	1,913
Interest and financing	1,550	1,788	2,416	4,000
Depletion and depreciation	15,764	17,006	31,640	34,579
Accretion of asset retirement obligation	82	96	163	191
Management fee (note 5)	494	855	811	1,498
	23,737	25,463	46,750	51,534
Income before taxes	4,779	34,100	7,081	54,582
Income and capital taxes	100	74	201	160
Future income tax reduction	(2,097)	(2,137)	(2,287)	(5,388)
	(1,997)	(2,063)	(2,086)	(5,228)
Net income and comprehensive income	6,776	36,163	9,167	59,810
Deficit, beginning of period	(360,477)	(312,785)	(348,027)	(314,234)
Distributions declared	(14,852)	(30,114)	(29,693)	(52,312)
Deficit, end of period	\$ (368,553)	\$ (306,736)	\$ (368,553)	\$ (306,736)
Net income per Trust Unit, basic and diluted	\$ 0.14	\$ 0.73	\$ 0.19	\$ 1.21
Weighted average number of Trust Units:				
Basic	49,495,475	49,352,859	49,477,748	49,335,032
Diluted	49,564,608	49,394,038	49,545,749	49,376,726

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Cash Flows

(\$000s) (unaudited)	Three Months Ended June 30		Six Months Ended June 30	
	2009	2008	2009	2008
Cash provided by (used in):				
Operating:				
Net income	\$ 6,776	\$ 36,163	\$ 9,167	\$ 59,810
Items not involving cash:				
Depletion and depreciation	15,764	17,006	31,640	34,579
Unit based compensation (note 4)	865	1,365	1,073	1,913
Future income tax reduction	(2,097)	(2,137)	(2,287)	(5,388)
Accretion of asset retirement obligation	82	96	163	191
Trust Units issued in lieu of management fee	494	855	811	1,498
Expenditures on reclamation	(51)	(165)	(115)	(238)
	21,833	53,183	40,452	92,365
Changes in non-cash working capital	105	(6,804)	3,055	(12,165)
	21,938	46,379	43,507	80,200
Financing:				
Long-term debt	(4,000)	(18,000)	16,000	(27,000)
Distributions paid	(14,848)	(25,169)	(54,416)	(47,362)
	(18,848)	(43,169)	(38,416)	(74,362)
Investing:				
Capital expenditures	(1,661)	(2,135)	(3,688)	(4,337)
Deposit on acquisition	-	(850)	-	(850)
Change in reclamation fund	(100)	9	(192)	(81)
Changes in non-cash working capital	(1,506)	(330)	(1,379)	(442)
	(3,267)	(3,306)	(5,259)	(5,710)
Increase (decrease) in cash	(177)	(96)	(168)	128
Cash, beginning of period	546	617	537	393
Cash, end of period	\$ 369	\$ 521	\$ 369	\$ 521

See accompanying notes to interim consolidated financial statements.

Notes to Interim Consolidated Financial Statements

For the period ended June 30, 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, 2008 and should be read in conjunction with the audited consolidated financial statements and notes for the year ended December 31, 2008.

Financial Instruments – Disclosures

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, “*Financial Instruments – Disclosures*”, to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust on December 31, 2009.

2. Long-Term Debt

Freehold has a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which \$156 million was drawn at June 30, 2009. 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 facilities are extendible annually with the latest review completed in May 2009. 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 2010.

3. Unitholders’ Capital

	June 30, 2009		December 31, 2008	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	49,459,429	567,310	49,316,813	564,828
Issued in lieu of management fee (note 5)	71,308	811	142,616	2,482
Balance, end of period	49,530,737	568,121	49,459,429	567,310

4. Unit Based Compensation

(a) Manager’s Long-Term Incentive Plan

Employees of the Manager, a wholly-owned subsidiary of Rife Resources Ltd., receive cash compensation in relation to the value of a specified number of notional units after a three-year vesting period. 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, 2009, Freehold expensed \$844,000 (2008 – \$1,324,000) as unit based compensation. The total for the six months ended June 30, 2009 was \$883,000 (2008 – \$1,675,000). At June 30, 2009, Freehold recorded \$1,682,000 (2008 – \$2,543,000) as a deferred long-term compensation asset, representing the

portion of the liability not yet charged to earnings. In addition, Freehold accrued \$1,947,000 (2008 – \$3,550,000) as a long-term liability and \$743,000 (2008 – \$1,166,000) as a current liability.

(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, 2009, there were 69,880 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, 2009, Freehold expensed \$21,000 (2008 – \$41,000) of unit based compensation with a corresponding increase to contributed surplus. The total for the six months ended June 30, 2009 was \$271,000 (2008 – \$238,000)

CONTRIBUTED SURPLUS (\$000s)	June 30 2009	December 31 2008
Balance, beginning of period	722	512
Trust Unit incentive compensation expense	271	210
Balance, end of period	993	722

5. Related Party Transactions

For the three months ended June 30, 2009, Freehold issued 35,654 Trust Units (2008 – 35,654 Trust Units) as a management fee to the Manager pursuant to a management agreement. The ascribed value of \$0.5 million (2008 – \$0.9 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, 2009 was 71,308 Trust Units (2008 – 71,308) with an ascribed value of \$0.8 million (2008 – \$1.5 million).

For the three months ended June 30, 2009, the Manager charged the Trust \$1.2 million in general and administrative costs (2008 – \$1.2 million). The total for the six month period ended June 30, 2009 was \$3.3 million (2008 – \$3.0 million). At June 30, 2009, there was \$0.4 million (2008 – \$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. Supplemental Cash Flow Disclosure

CASH EXPENSES PAID (\$000s)	Three Months Ended June 30		Six Months Ended June 30	
	2009	2008	2009	2008
Interest	1,617	1,668	2,427	3,725
Taxes	101	13	292	203

7. Contingencies

In the second quarter of 2009, a statement of claim was filed against the Trust in the amount of \$9.0 million. The claim involves disputed land interests and royalty obligations. After receiving outside legal advice, the Trust has assessed the claim, believes it has no merit, and intends to aggressively defend itself in the claim. The outcome is not determinable; therefore no amounts have 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 ⁽¹⁾⁽²⁾⁽³⁾⁽⁵⁾

Senior Vice-President
Montrusco Bolton Investments Inc.

Russell J. Hiscock

President and Chief Executive Officer
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

STOCK EXCHANGE

Toronto Stock Exchange
Trading Symbol: FRU.UN

TRUSTEE AND TRANSFER AGENT

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

(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

Garry W. Bieber

Vice-President, Production

J. Frank George

Vice-President, Exploitation

Darren G. Gunderson

Vice-President, Finance and Chief
Financial Officer

Michael J. Okrusko

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

HEAD OFFICE

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Freehold Royalty Trust
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INVESTOR RELATIONS

Karen C. Taylor
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WEBSITE

www.freeholdtrust.com

2009 SECOND QUARTER TRADING SUMMARY

High – \$15.18
Low – \$8.70
Close – \$13.85
Volume Traded – 8.8 million
Trust Units Outstanding – 49.5 million

2009 SECOND QUARTER DISTRIBUTIONS DECLARED

<u>Record Date</u>	<u>Payment Date</u>	<u>Per Trust Unit</u>
April 30, 2009	May 15, 2009	\$0.10
May 31, 2009	June 15, 2009	\$0.10
June 30, 2009	July 15, 2009	<u>\$0.10</u>
		<u>\$0.30</u>

Tax information and historical
distributions are available on our
website.