

Quarterly Report

THREE MONTHS ENDED MARCH 31, 2009

Freehold Royalty Trust Announces
2009 First Quarter Results

RESULTS AT A GLANCE

Financial (\$000s, except as noted)	Three Months Ended March 31		
	2009	2008	Change
Gross revenue	26,618	48,574	-45%
Net income	2,391	23,647	-90%
Per Trust Unit, basic and diluted (\$)	0.05	0.48	-90%
Cash provided by operating activities	21,569	33,821	-36%
Per Trust Unit (\$)	0.44	0.69	-36%
Funds generated from operations (1)	18,619	39,182	-52%
Per Trust Unit (\$)	0.38	0.79	-52%
Capital expenditures	2,027	2,202	-8%
Distributions declared	14,841	22,198	-33%
Per Trust Unit (\$) (2)	0.30	0.45	-33%
Long-term debt, period end	160,000	169,000	-5%
Unitholders' equity, period end	208,122	253,395	-18%
Trust Units (000s) (3)	49,460	49,317	-
Operating (per boe) (4)			
Average daily production (boe/d)	7,522	8,152	-8%
Average price realizations (\$)	37.85	64.16	-41%
Operating netback (\$) (1)	33.13	59.18	-44%

(1) See non-GAAP measures.

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

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

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

MAY DISTRIBUTION DECLARED

The Board of Directors has declared the May distribution of \$0.10 per Trust Unit, which will be paid on June 15, 2009 to Unitholders of record on May 31, 2009 (ex-distribution date May 27, 2009). Including the June 15, 2009 payment, our 12-month trailing cash distributions total \$2.60 per Trust Unit.

Message to Unitholders

Overall, our results for the first quarter of 2009 reflect lower production and lower selling prices due to the steep decline in commodity prices. Cash provided by operating activities, funds generated from operations, and net income all declined significantly due to lower revenues. Our production, which remains unhedged, was down 8% in the first quarter, as drilling activity was insufficient to offset natural production declines.

The Board has established a distribution policy of \$0.10 per Trust Unit per month based on the key operating assumptions outlined on page 5. We will review this policy monthly and make adjustments, if necessary, to ensure that cash distributions are in line with cash flow.

The oil and gas industry in western Canada continues to experience a difficult business environment. Activity levels have cooled as weak commodity markets, along with restricted access to credit and capital markets, have forced producers to reduce capital budgets. In February, in the midst of the winter drilling season, the Canadian Association of Oilwell Drilling Contractors further downgraded its drilling outlook for 2009 by 22%.

On March 3, 2009, the Alberta Government announced a short-term stimulus plan to encourage conventional oil and natural gas activity in the province. All new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010 qualify for drilling credits and Crown royalty reductions. While the stimulus plan is expected to have a positive impact on industry activity levels in the coming months, its announcement had a negative impact on first quarter drilling, with producers delaying commencement of new wells until after April 1, in order to qualify for the incentives.

Drilling on our royalty lands reflected the overall decline in industry activity levels, particularly in Alberta. The largest decline was in shallow gas areas, where continued investment is uneconomic at today's prices. As at March 31, 2009, there were 30 (2008 – 65) licensed drilling locations on our royalty lands. First quarter drilling on our working interest properties was also significantly lower than last year. We participated in the drilling of three (0.4 net) wells in Saskatchewan and two (0.1 net) wells in Alberta, with a 100% net success rate.

We believe that lower reinvestment will lead to eventual price recoveries, with natural gas recovering more slowly than oil due to a continuing over supply situation in North America. One positive trend for Freehold, given our heavy-oil weighted production profile, is a strengthening in demand for Canadian heavy crude. Producers in western Canada have been able to access U.S. markets via new pipelines added in 2006, and many North American refineries have been retooled to process heavier grades of crude. As a result, heavy oil differentials have narrowed from historical levels.

I'm pleased to report that our banking syndicate has completed its annual review of our credit facilities with no changes to our \$210 million borrowing base. We currently have \$50 million of available capacity under these facilities.

In closing, I would like to take this opportunity to commend the management and staff of Rife Resources, who do an exemplary job of managing the assets of Freehold on behalf of the Unitholders, and welcome my successor, Bill Ingram. With my retirement as President and CEO effective today, this is my final Message to Unitholders. Under Bill's leadership, I am confident that the management of Freehold is in good hands.

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



David J. Sandmeyer
President and Chief Executive Officer

Management's Discussion and Analysis (MD&A)

The following discussion is management's opinion about the operating and financial results of Freehold Royalty Trust, Freehold Resources Ltd. and Petrovera Resources (a general partnership) (collectively, Freehold or the Trust), for the three months ended March 31, 2009 and previous periods, and the outlook for Freehold based on information available as at May 13, 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 March 31, 2009 and March 31, 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 May 13, 2009, and contains forward-looking statements including our expectations for commodity prices and activity levels referred to in the Message to Unitholders;; Future Income Tax; and our expectations for commodity prices and activity levels and key operating assumptions 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 expanding 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; the impact of increasing competition; our expectation for 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 our development and acquisition activities. The key operating assumptions with respect to the forward-looking statements referred to above are detailed under 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 Canadian 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 oil and gas industry in western Canada continues to experience a difficult business environment. Activity levels have cooled as weak commodity markets, along with restricted access to credit and capital markets, have forced producers to reduce capital budgets. In February, in the midst of the winter drilling season, the Canadian Association of Oilwell Drilling Contractors further downgraded its drilling outlook for 2009 by 22%. We believe that lower reinvestment will lead to eventual price recoveries, with natural gas recovering more slowly than oil due to a continuing over supply situation in North America.

On March 3, 2009, the Alberta Government announced a short-term stimulus plan to encourage conventional oil and natural gas activity in the province. All new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010 qualify for drilling credits and Crown royalty reductions. While the stimulus plan is expected to have a positive impact on industry activity levels in the coming months, its announcement had a negative impact on first quarter activity levels, with producers delaying commencement of new wells until after April 1, in order to qualify for the incentives.

DISTRIBUTION POLICY

Our Board has established a distribution policy of \$0.10 per Trust Unit per month based on the key operating assumptions outlined below. We will review this policy monthly and make adjustments, if necessary, to ensure that cash distributions are in line with cash flow.

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

(1) Excludes unit based compensation.

There are no material variances between our current guidance and the guidance in our 2008 annual MD&A.

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. A sensitivity analysis of the potential impact of key variables on distributions to Unitholders is provided on page 40 of our 2008 annual report.

Development Activities

INDUSTRY ACTIVITY

As anticipated, industry activity in the first quarter of 2009 was down significantly, 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, a total of 4,434 wells were drilled in western Canada in the first quarter of 2009, 552 fewer than in the first quarter last year.

ROYALTY INTEREST LANDS

Drilling on our royalty lands reflected the overall decline in industry activity levels, particularly in Alberta. The largest decline was in shallow gas areas, where continued investment is uneconomic at today's prices. As at March 31, 2009, there were 30 (2008 – 65) licensed drilling locations on our royalty lands.

DRILLING ON ROYALTY LANDS

	Three Months Ended March 31		
	2009	2008	Change
Unitized wells			
Gross	127	119	7%
Equivalent net (1)	0.7	0.5	40%
Non-unitized wells			
Gross	58	111	-48%
Equivalent net (1)	2.3	5.0	-54%
Total			
Gross	185	230	-20%
Equivalent net (1)	3.0	5.5	-45%

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

WORKING INTEREST PROPERTIES

First quarter drilling on working interest properties was also significantly lower than last year. We participated in the drilling of three (0.4 net) wells in Saskatchewan and two (0.1 net) wells in Alberta, with a 100% net success rate.

DRILLING ON WORKING INTEREST PROPERTIES

	Three Months Ended March 31			
	2009		2008	
	Gross	Net	Gross	Net
Oil	4	0.5	4	0.5
Natural gas	1	-	7	0.2
Other	-	-	1	0.1
Total	5	0.5	12	0.8

Quarterly Performance and Trends

Our results are 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 reasonable 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 results.

- WTI crude prices have exhibited significant volatility in the last eight quarters. Prices climbed steadily throughout 2007 and into 2008, when they reached an all time high of over US\$147 per barrel in July 2008. During this period, higher oil prices boosted our revenues and cash distributions, although the gains were somewhat muted by an increase in the value of the Canadian dollar relative to its U.S. counterpart. The global economic downturn that began in mid-2008 reduced demand for oil, causing WTI prices to weaken significantly during the past six months. The Canadian dollar also weakened during this period, which mitigated the overall negative impact of the commodity price decline.
- Demand for Canadian heavy crude has strengthened in recent years as producers in western Canada have been able to access U.S. markets via new pipelines added in 2006. In addition, many North American refineries have been retooled to process heavier grades of crude. As a result, heavy oil differentials have narrowed from historical levels.
- 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 six months.
- We have adjusted our monthly distributions in response to changing commodity prices. In April 2008, we raised the monthly 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 monthly rate to \$0.10 per Trust Unit to preserve operating stability and financial flexibility through the current period of low commodity prices.
- The substantive enactment in June 2007 of Bill C-52 *Budget Implementation Act, 2007*, resulted in the initial recording of a \$54.3 million future income tax expense in the second quarter of 2007. In addition, corporate tax rate reductions substantively enacted in the first quarter of 2009 and the fourth quarter of 2007 resulted in reductions of future income tax of \$0.2 million and \$5.9 million, respectively.
- On August 31, 2007, we acquired gross overriding royalty (GORR) interests on 309,800 gross acres of land in Alberta and Saskatchewan for \$57.6 million. On September 5, 2007, we acquired a 7% GORR interest on 9,078 gross acres of land at Dixonville, Alberta, for \$32.8 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 the past few years, the oil and gas industry has experienced rising costs, particularly in Alberta where strong economic growth and oil sands development heightened demand for people and services. We have experienced cost escalation on our working interest properties; however, the impact on our overall results is mitigated by our large proportion of royalty interest production, which is unencumbered by operating expenses.
- Fluctuations in our Trust Unit price resulted in corresponding changes in unit based incentive compensation, which are based in part on the closing unit price at each quarter end.
- Quarterly fluctuations in the percentage of our total boe production derived from royalty interests will result in corresponding fluctuations in operating expenses and third party royalty expenses. Over the past eight quarters, royalty production volumes have varied between 63% and 72% of total boe production.
- In the second quarter of 2007, two natural gas wells in British Columbia were converted from royalty interests to working interests upon payout. To account for the change in status of the two wells, royalty volumes and revenues were adjusted, and in their place working interest volumes were booked, along with associated operating and royalty expenses.

QUARTERLY REVIEW	2009	2008				2007		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial (\$000s, except as noted)								
Revenue, net of royalty expense	25,315	33,174	58,210	59,563	46,553	39,218	36,086	35,907
Distributions declared	14,841	54,387	37,050	30,114	22,198	28,096	22,165	22,151
Per Trust Unit (\$) (1) (2)	0.30	1.10	0.75	0.61	0.45	0.57	0.45	0.45
Net income (loss)	2,391	13,374	36,772	36,163	23,647	19,067	12,487	(42,533)
Per Trust Unit, basic and diluted (\$)	0.05	0.27	0.74	0.73	0.48	0.39	0.25	(0.86)
Cash provided by operating activities	21,569	41,672	57,380	46,379	33,821	32,503	29,796	30,829
Per Trust Unit (\$)	0.44	0.84	1.16	0.94	0.69	0.66	0.61	0.63
Funds generated from operations (3)	18,619	26,942	51,977	53,183	39,182	32,591	29,907	30,213
Per Trust Unit (\$)	0.38	0.55	1.05	1.08	0.79	0.66	0.61	0.61
Property and royalty acquisitions	-	(782)	8,475	-	-	26	90,430	-
Capital expenditures	2,027	3,770	9,222	2,135	2,202	3,901	1,960	2,830
Long-term debt	160,000	140,000	141,000	151,000	169,000	178,000	179,000	100,000
Trust Units outstanding								
Weighted average (000s)	49,460	49,424	49,389	49,353	49,317	49,282	49,246	49,210
At quarter end (000s)	49,495	49,459	49,424	49,388	49,352	49,317	49,281	49,246
Operating (\$/boe, except as noted)								
Daily production (boe/d)	7,522	7,779	7,613	7,674	8,152	8,591	8,219	8,566
Royalty interest production (%)	70	71	71	72	71	70	69	63
Average selling price	37.85	46.55	83.47	86.43	64.16	50.57	48.28	48.21
Operating netback (2)	33.13	42.14	79.14	81.21	59.18	46.47	43.65	42.28
Operating expenses	4.27	4.21	3.97	4.08	3.58	3.14	4.07	3.79
Working interest properties	14.27	14.31	13.51	14.37	12.54	10.56	13.17	10.34
General and administrative expenses	3.98	2.20	1.95	2.15	3.16	1.80	1.28	1.59
Benchmark Prices								
WTI crude oil (US\$/bbl)	43.08	58.69	117.98	123.98	97.86	90.68	75.38	65.04
Exchange rate (Cdn\$/US\$)	0.80	0.83	0.96	0.99	1.00	1.02	0.96	0.91
Edmonton Par crude oil (Cdn\$)	49.66	63.21	121.85	126.07	97.50	86.42	79.95	71.93
Light/heavy oil differential (Cdn\$/bbl)	5.25	13.72	16.43	21.43	19.47	29.37	23.95	21.02
Bow River/Hardisty (Cdn\$/bbl)	44.41	49.49	105.42	104.64	78.04	57.05	56.00	50.91
AECO natural gas (Cdn\$/Mcf)	5.62	6.78	9.24	9.35	7.13	6.00	5.61	7.37
Unit Trading Performance								
High (\$)	11.76	18.43	24.35	24.40	19.29	15.85	15.85	15.85
Low (\$)	6.87	9.15	16.01	17.51	14.55	14.46	12.51	13.77
Close (\$)	8.90	10.49	17.10	23.99	18.04	15.60	15.26	14.53
Volume (000s)	9,310	10,474	10,263	8,993	6,740	7,036	5,172	6,853

(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, results for the first quarter of 2009 reflect lower production and lower selling prices due to the steep decline in commodity prices. 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 March 31		
	2009	2008	Change
Cash provided by operating activities	21,569	33,821	-36%
Changes in non-cash working capital	(2,950)	5,361	-155%
Funds generated from operations	18,619	39,182	-52%
Per Trust Unit (\$)	0.38	0.79	-52%
Net income	2,391	23,647	-90%
Per Trust Unit, basic and diluted (\$)	0.05	0.48	-90%

PRODUCTION

On a boe basis, our production was down 8% in the first quarter, as drilling activity was insufficient to offset natural production declines. Royalty interests contributed 70% (2008 Q1 – 71%) of total volumes produced. Our production mix for the quarter was approximately 36% natural gas and 64% liquids (32% heavy oil, 28% light and medium oil, and 4% NGL).

AVERAGE DAILY PRODUCTION	Three Months Ended March 31		
	2009	2008	Change
Royalty lands			
Oil (bbls/d)	2,834	3,135	-10%
NGL (bbls/d)	276	230	20%
Natural gas (Mcf/d)	12,975	14,750	-12%
Oil equivalent (boe/d)	5,273	5,823	-9%
Working interest properties			
Oil (bbls/d)	1,645	1,763	-7%
NGL (bbls/d)	67	69	-3%
Natural gas (Mcf/d)	3,227	2,982	8%
Oil equivalent (boe/d)	2,250	2,329	-3%
Total Trust			
Oil (bbls/d)	4,479	4,898	-9%
NGL (bbls/d)	343	299	15%
Natural gas (Mcf/d)	16,202	17,732	-9%
Oil equivalent (boe/d)	7,522	8,152	-8%
Number of days in period (days)	90	91	-1%
Total volumes during period (Mboe)	677	742	-9%

MARKETING AND HEDGING

As at March 31, 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 15% 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.

Our production was unhedged in the first quarter, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our board of directors.

COMMODITY PRICES

The following table is a summary of average benchmark prices for the first 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 and strong refinery demand for this product type. 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 realizations.

AVERAGE BENCHMARK PRICES (1)	Three Months Ended		
	March 31		
	2009	2008	Change
WTI crude oil (US\$/bbl)	43.08	97.86	-56%
US\$/Cdn\$ exchange rate	0.8031	0.9960	-19%
Edmonton Par crude oil (Cdn\$/bbl)	49.66	97.50	-49%
Bow River/Hardisty (Cdn\$/bbl)	44.41	78.04	-43%
Western Canada Select/Hardisty (Cdn\$/bbl)	42.54	76.70	-45%
AECO natural gas (Cdn\$/Mcf)	5.62	7.13	-21%

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

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

AVERAGE SELLING PRICES	Three Months Ended		
	March 31		
	2009	2008	Change
Oil (\$/bbl)	41.41	75.23	-45%
NGL (\$/bbl)	40.75	67.43	-40%
Oil and NGL (\$/bbl)	41.36	74.78	-45%
Natural gas (\$/Mcf)	5.26	7.58	-31%
Oil equivalent (\$/boe)	37.85	64.16	-41%

Revenue

Gross revenue declined 45% in the first 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 March 31	
	2009 vs. 2008	2008 vs. 2007
Oil and NGL		
Production decrease	(1,609)	(1,865)
Price increase (decrease)	(15,802)	12,787
Net increase (decrease)	(17,411)	10,922
Natural gas		
Production decrease	(818)	(181)
Price increase (decrease)	(3,744)	324
Net increase (decrease)	(4,562)	143
Other (1)	17	505
Gross revenue increase (decrease)	(21,956)	11,569

(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. Crown royalty rates are tied to commodity prices and production volumes. Annual mineral tax is payable to the Crown in the first quarter of the year.

ROYALTY EXPENSE AND MINERAL TAX (1) (\$000s, except as noted)	Three Months Ended March 31		
	2009	2008	Change
Working interest properties			
Crown royalties	463	1,096	-58%
Third party royalties	164	329	-50%
Mineral tax	148	127	17%
Working interest properties	775	1,552	-50%
Per boe (\$)	3.83	7.32	-48%
Royalty lands			
Crown royalties	-	-	-
Third party royalties	-	-	-
Mineral tax	528	469	13%
Royalty lands	528	469	13%
Per boe (\$)	1.11	0.89	25%
Total Trust	1,303	2,021	-36%
Per boe (\$)	1.92	2.72	-29%

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

OPERATING EXPENSES

Operating expenses in the first quarter of 2009 included approximately \$300,000 related to 2008. Excluding the prior period amount, operating costs on our working interest properties were consistent with the first quarter last year. As certain components of operating expenses are fixed costs, lower production volumes in the first quarter of 2009 led to higher operating costs per boe.

OPERATING EXPENSES	Three Months Ended March 31		
	2009	2008	Change
Working interest properties (\$000s)	2,890	2,657	9%
Per boe (\$)	14.27	12.54	14%
Royalty lands (\$000s) (1)	-	-	-
Per boe (\$)	-	-	-
Total operating expenses (\$000s)	2,890	2,657	9%
Total Trust (\$/boe)	4.27	3.58	19%

(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 (\$000s)	Three months ended March 31, 2009		
	Royalty Interest Lands	Working Interest Properties	Total Trust
Gross revenue (1)	18,503	8,115	26,618
Royalty expense and mineral tax (2)	(528)	(775)	(1,303)
Net revenue	17,975	7,340	25,315
Operating expense	-	(2,890)	(2,890)
Operating netback	17,975	4,450	22,425

(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 quarter of 2009 was 44% lower than last year, due to lower commodity prices and higher operating expenses, partly offset by lower royalty expense and mineral tax.

OPERATING NETBACK (\$/boe)	Three Months Ended March 31		
	2009	2008	Change
Gross revenue (1)	39.32	65.48	-40%
Royalty expense and mineral tax (2)	(1.92)	(2.72)	-29%
Operating expenses	(4.27)	(3.58)	19%
Operating netback	33.13	59.18	-44%

(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 first quarter of 2009 reflect higher compensation expense due to increased staff levels. G&A expenses in the first quarter included \$2.2 million charged by the Manager for time and direct costs incurred on behalf of the Trust.

G&A EXPENSES	Three Months Ended March 31		
	2009	2008	Change
G&A expenses (\$000s)	2,694	2,343	15%
Per boe (\$)	3.98	3.16	26%
As a percentage of revenue	10%	5%	100%

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 2006 LTIP grants vested in January 2009, and \$81,000 of unit based compensation was paid out in the first quarter. At March 31, 2009, we recorded \$239,000 (2008 – \$859,000) as a deferred long-term compensation asset and \$34,000 (2008 – \$106,000) as the current portion of deferred long-term compensation, representing the portion of the liability not yet charged to earnings. In addition, we accrued \$305,000 (2008 – \$1,303,000) as a long-term liability and \$131,000 (2008 – \$423,000) as a current liability.

Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. As at March 31, 2009, there were 68,262 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

UNIT BASED COMPENSATION	Three Months Ended March 31		
	2009	2008	Change
Manager's long-term incentive plan	39	351	-89%
Deferred trust unit plan	250	197	27%
Unit based compensation	289	548	-47%
Per boe (\$)	0.43	0.74	-42%
As a percentage of revenue	1%	1%	0%

INTEREST EXPENSES

Interest expense declined 61% in the first 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 first quarter last year.

INTEREST EXPENSES	Three Months Ended March 31		
	2009	2008	Change
Net interest expense (000s)	866	2,212	-61%
Per boe (\$)	1.28	2.98	-57%

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)	As at March 31		
	2009	2008	Change
Depletion and depreciation	15,876	17,573	-10%
Accretion of asset retirement obligation	81	95	-15%
Total depletion, depreciation and accretion expenses	15,957	17,668	-10%
Per boe (\$)	23.57	23.82	-1%

MANAGEMENT FEES

The quarterly management fee, which is paid in Trust Units, was 35,654 Trust Units for the first quarter of 2009, unchanged from 2008. The ascribed value was 51% lower because of a lower Trust Unit price at the end of the first quarter of 2009.

MANAGEMENT FEES (Paid in Trust Units)	Three Months Ended March 31		
	2009	2008	Change
Trust Units issued in payment of management fees	35,654	35,654	0%
Ascribed value (\$000s) (1)	317	643	-51%
Per boe (\$)	0.47	0.87	-46%

(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 reduction in future income tax in the first quarter of 2009.

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 \$2.0 million in the first quarter of 2009, including \$1.0 million on Bakken drilling in Southeast Saskatchewan and \$0.6 million at Pembina Cardium Unit No. 9.

ACQUISITIONS AND CAPITAL EXPENDITURES (\$000s, except as noted)	Three Months Ended March 31		
	2009	2008	Change
Capital expenditures	2,027	2,202	-8%
Change in reclamation fund	92	90	2%
	2,119	2,292	-8%

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 issues, payments to royalty owners are often delayed longer. Therefore, working capital at each period end can vary due to volume and prices changes during the period.

COMPONENTS OF WORKING CAPITAL (\$000s)	Mar. 31 2009	Dec. 31 2008	Sept. 30 2008	June 30 2008	Mar. 31 2008
Cash	546	537	212	521	617
Current portion of deferred compensation	34	-	38	194	106
Accounts receivable	21,870	23,261	38,507	42,538	35,131
Current assets	22,450	23,798	38,757	43,253	35,854
Distributions declared	(4,950)	(29,676)	(12,356)	(12,347)	(7,403)
Current portion of unit based compensation	(131)	(83)	(452)	(1,166)	(423)
Accounts payable and accrued liabilities	(15,780)	(14,094)	(14,830)	(11,708)	(11,433)
Current liabilities	(20,861)	(43,853)	(27,638)	(25,221)	(19,259)
Working capital (1)	1,589	(20,055)	11,119	18,032	16,595

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

DEBT ANALYSIS

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 the end of the first quarter, we had \$50 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. This review process was recently completed with no changes to our borrowing base.

DEBT ANALYSIS (\$000s)	As at March 31		
	2009	2008	Change
Long-term debt	160,000	169,000	-5%
Short-term debt	-	-	-
Total debt	160,000	169,000	-5%
Less: working capital	1,589	16,595	-90%
Net debt obligations	158,411	152,405	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 March 31, 2009, the Trust was in compliance with all such covenants.

FINANCIAL LEVERAGE AND COVERAGE RATIOS (1)	As at March 31		
	2009	2008	Change
Net debt to funds generated from operations (times)	1.1	1.2	-8%
Net debt to distributions (times)	1.2	1.6	-25%
Distributions to interest expense (times)	24.0	12.0	100%
Net debt to net debt plus equity (%)	43%	38%	13%

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

DISTRIBUTIONS

Distributions in the first quarter totalled \$0.30 per Trust Unit. From inception to March 31, 2009, the Trust has distributed \$739.3 million (\$19.43 per Trust Unit) to Unitholders.

ACCUMULATED DISTRIBUTIONS	Three Months Ended March 31	
	2009	2008
Distributions declared (\$000s)	14,841	22,198
Accumulated, beginning of period	724,418	580,669
Accumulated, end of period	739,259	602,867
Distributions per Trust Unit (\$) (1)	0.30	0.45
Accumulated, beginning of period	19.13	16.22
Accumulated, end of period	19.43	16.67

(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 \$16.3 million for the first quarter of 2009 (2008 – \$15.6 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 (\$000s)	Three Months Ended March 31	
	2009	2008
Cash provided by operating activities	21,569	33,821
Net income	2,302	23,647
Distributions declared	14,841	22,198
Excess of cash provided by operating activities over distributions declared	45%	52%
Excess (shortfall) of net income over distributions declared	(84%)	7%

UNITHOLDERS' CAPITAL

As at March 31, 2009 and May 13, 2009, there were 49,495,083 Trust Units outstanding.

On January 1, 2009, the Board granted 20,020 deferred trust units to eligible directors as part of their annual compensation. Each eligible director received 2,860 deferred trust units and the Chair of the Board received 5,720 deferred trust units. As at March 31, 2009, there were 68,262 deferred trust units outstanding and at May 13, 2009, there were 68,845 deferred trust units outstanding.

TRUST UNITS OUTSTANDING	Three Months Ended		
	March 31		
	2009	2008	Change
Weighted average			
Basic	49,459,825	49,317,205	0%
Diluted	49,526,680	49,359,757	0%
At period end	49,495,083	49,352,467	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.

International Financial Reporting Standards (IFRS)

As discussed in our 2008 annual MD&A, we are continuing to finalize our plan for conversion to IFRS effective January 1, 2011. Our plan will address 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. We have assigned internal staff to lead the conversion project and retained an external advisor to assist us. Throughout the year, we will provide IFRS conversion progress updates as this information becomes available.

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).

Internal Controls

There were no changes in the Trust's ICFR during the three months ended March 31, 2009 that materially affected the Trust's ICFR.

Consolidated Balance Sheets

(\$000s) (unaudited)	March 31 2009	December 31 2008
Assets		
Current assets:		
Cash	\$ 546	\$ 537
Accounts receivable	21,870	23,261
Current portion of deferred long-term compensation (note 4)	34	-
	22,450	23,798
Reclamation fund	1,919	1,827
Deferred long-term compensation (note 4)	239	120
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$465,955 (2008 - \$450,079)	412,698	426,530
	\$ 437,306	\$ 452,275
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	\$ 4,950	\$ 29,676
Accounts payable and accrued liabilities	15,780	14,094
Current portion of unit based compensation (note 4)	131	83
	20,861	43,853
Asset retirement obligation	5,698	5,663
Unit based compensation (note 4)	305	243
Long-term debt (note 2)	160,000	140,000
Future income tax liability	42,320	42,511
Unitholders' equity:		
Unitholders' capital (note 3)	567,627	567,310
Contributed Surplus (note 4)	972	722
Deficit	(360,477)	(348,027)
	208,122	220,005
	\$ 437,306	\$ 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 March 31	
	2009	2008
Revenue:		
Royalty income and working interest sales	\$ 26,618	\$ 48,574
Royalty expense and mineral tax	(1,303)	(2,021)
	<u>25,315</u>	<u>46,553</u>
Expenses:		
Operating	2,890	2,657
General and administrative	2,694	2,343
Unit based compensation (note 4)	289	548
Interest on long-term debt	866	2,212
Depletion and depreciation	15,876	17,573
Accretion of asset retirement obligation	81	95
Management fee (note 5)	317	643
	<u>23,013</u>	<u>26,071</u>
Net income before taxes	2,302	20,482
Income and capital taxes	101	86
Future income tax reduction	(190)	(3,251)
	<u>(89)</u>	<u>(3,165)</u>
Net income and comprehensive income	2,391	23,647
Deficit, beginning of period	(348,027)	(314,234)
Distributions declared	(14,841)	(22,198)
Deficit, end of period	\$ (360,477)	\$ (312,785)
Net income per Trust Unit, basic and diluted	\$ 0.05	\$ 0.48
Weighted average number of Trust Units:		
Basic	49,459,825	49,317,205
Diluted	49,526,680	49,359,757

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Cash Flows

(\$000s) (unaudited)	Three Months Ended March 31	
	2009	2008
Cash provided by (used in):		
Operating:		
Net income	\$ 2,391	\$ 23,647
Items not involving cash:		
Depletion and depreciation	15,876	17,573
Unit based compensation (note 4)	208	548
Future income tax reduction	(190)	(3,251)
Accretion of asset retirement obligation	81	95
Trust Units issued in lieu of management fee	317	643
Expenditures on reclamation	(64)	(73)
	18,619	39,182
Changes in non-cash working capital	2,950	(5,361)
	21,569	33,821
Financing:		
Long-term debt	20,000	(9,000)
Distributions paid	(39,568)	(22,193)
	(19,568)	(31,193)
Investing:		
Capital expenditures	(2,027)	(2,202)
Change in reclamation fund	(92)	(90)
Changes in non-cash working capital	127	(112)
	(1,992)	(2,404)
Increase in cash	9	224
Cash, beginning of period	537	393
Cash, end of period	\$ 546	\$ 617

See accompanying notes to interim consolidated financial statements.

Notes to Interim Consolidated Financial Statements

For the period ended March 31, 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.

2. Long-Term Debt

Freehold has a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which \$160 million was drawn at March 31, 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 will 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

	March 31, 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	35,654	317	142,616	2,482
Balance, end of period	49,495,083	567,627	49,459,429	567,310

4. Unit Based Compensation

(a) Manager's Long-Term Incentive Plan

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. For the three months ended March 31, 2009, Freehold expensed \$39,000 (2008 – \$351,000) as unit based compensation. At March 31, 2009, Freehold recorded \$239,000 (2008 – \$859,000) as a deferred long-term compensation asset and \$34,000 (2008 – \$106,000) as the current portion of deferred long-term compensation, representing the portion of the liability not yet charged to earnings. In addition, Freehold accrued \$305,000 (2008 – \$1,303,000) as a long-term liability and \$131,000 (2008 – \$423,000) as a current liability. The 2006 LTIP grants of \$81,000 were paid out in the quarter.

(b) Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. As at March 31, 2009, there were 68,262 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

For the three months ended March 31, 2009, Freehold expensed \$250,000 (2008 – \$197,000) of unit based compensation with a corresponding increase to contributed surplus.

CONTRIBUTED SURPLUS (\$000s)	March 31 2009	December 31 2008
Balance, beginning of period	722	512
Trust Unit incentive compensation expense	250	210
Balance, end of period	972	722

5. Related Party Transactions

For the three months ended March 31, 2009, Freehold issued 35,654 Trust Units (2008 – 35,654 Trust Units) as management fee to the Manager, Rife Resources Ltd., pursuant to a management agreement. The ascribed value of \$0.3 million (2008 – \$0.6 million) is based on the closing price of the Trust Units on the last trading day of the quarter.

For the three months ended March 31, 2009, the Manager charged the Trust \$2.2 million in general and administrative costs (2008 – \$1.8 million). At March 31, 2009, there was \$0.6 million (2008 – \$0.3 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 March 31	
	2009	2008
Interest	780	2,046
Taxes	191	190

Corporate Information

BOARD OF DIRECTORS

William W. Siebens
President and Chief Executive Officer
Candor Investments Ltd.

D. Nolan Blades ⁽¹⁾⁽²⁾⁽³⁾⁽⁵⁾
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

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

David J. Sandmeyer
President and Chief Executive Officer
Rife Resources Ltd.

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

William W. Siebens
Chair of the Board

David J. Sandmeyer
President and Chief Executive Officer

William O. Ingram
Executive Vice-President and Chief
Operating 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

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Karen C. Taylor
Manager, Investor Relations and
Corporate Secretary
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Toll Free: 1-888-257-1873
Email: ir@freeholdtrust.com

WEBSITE

www.freeholdtrust.com

2009 FIRST QUARTER TRADING SUMMARY

High – \$11.73
Low – \$6.87
Close – \$8.90
Volume Traded – 9.3 million
Trust Units Outstanding – 49.5 million

2009 FIRST QUARTER DISTRIBUTIONS DECLARED

<u>Record Date</u>	<u>Payment Date</u>	<u>Per Trust Unit</u>
Jan. 31, 2009	Feb. 15, 2009	\$0.10
Feb. 28, 2009	Mar. 15, 2009	\$0.10
Mar. 31, 2009	Apr. 15, 2009	<u>\$0.10</u>
		<u>\$0.30</u>

Tax information and historical
distributions are available on our
website.