

## Freehold Royalty Trust Announces 2007 First Quarter Results

### FIRST QUARTER HIGHLIGHTS

- Revenue increased 6% to \$37 million.
- Price realizations averaged \$47.40 per boe, 8% higher than the first quarter a year ago.
- Operating netback increased 5% to \$42.06 per boe.
- Production averaged 8,564 barrels of oil equivalent (boe) per day, down 3% year over year, but up 3% from the fourth quarter of 2006.
- Funds generated from operations totalled \$0.58 per Trust Unit, unchanged from the first quarter of 2006.
- Distributions declared in the first quarter amounted to \$0.45 per Trust Unit, 17% lower than last year.

The regular monthly distribution of \$0.15 per Trust Unit will be paid on June 15, 2007 to Unitholders of record on May 31, 2007 (ex-distribution date May 29, 2007). Including the June 15, 2007 payment, 12-month trailing cash distributions total \$1.95 per Trust Unit. Production levels, commodity prices, operating costs, and other expenses remain in line with our expectations, and our distribution guidance for 2007 remains unchanged at \$1.80 per Trust Unit.

Results at a Glance	Three Months Ended		
	March 31		
	2007	2006	Change
<b>Financial</b> (\$000s, except as noted)			
Gross revenue	37,005	35,007	6%
Operating income	32,425	31,802	2%
Net income	9,787	8,766	12%
Per Trust Unit, basic and diluted (\$)	0.20	0.18	11%
Funds generated from operations	28,297	28,198	—
Per Trust Unit (\$)	0.58	0.58	—
Capital expenditures	3,476	1,601	117%
Distributions declared	22,133	26,483	-16%
Per Trust Unit (\$) <sup>(1)</sup>	0.45	0.54	-17%
Long-term debt, period end	99,000	105,000	-6%
Unitholders' equity, period end	332,836	382,449	-13%
Trust Units (000s) <sup>(2)</sup>	49,175	49,032	—
<b>Operating</b>			
Average daily production (boe/d)	8,564	8,794	-3%
Average price realizations (\$/boe)	47.40	43.78	8%
Operating netback (\$/boe)	42.06	40.18	5%

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

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

## Message to Unitholders

Last year's \$11 million capital program is showing results and we are very pleased with our production performance in the first quarter. While total production was 3% lower year over year, volumes are up 3% from the fourth quarter. As a result of the success of our development programs in Hayter and Southeast Saskatchewan, we have increased our 2007 development budget to \$9.5 million.

Industry drilling declined in the first quarter of 2007 with 21% fewer wells drilled across Canada, a reminder that commodity prices are a key driver for our industry. Drilling on our royalty lands, which generally mirrors industry activity, was level with the first quarter last year on equivalent net basis, although there are currently fewer licensed drilling locations on our lands. Activity levels and production volumes are expected to be lower in the second quarter, due to a prolonged spring break-up and annual maintenance shut-downs. Demand for people and services, particularly in Alberta, remains high, although lower commodity prices have reduced industry activity levels and we believe that costs are beginning to stabilize.

WTI crude oil prices were 8% lower quarter-over-quarter, while the price spread between light and heavy oil narrowed dramatically. Historically, differentials are the widest in the first quarter of the year, yet there was a 41% improvement over the first quarter last year. We believe this improvement may be signalling a fundamental change in the heavy oil price differential, as heavy oil markets continue to benefit from the new pipeline access to U.S. markets that was added in 2006. With roughly 38% of our total production mix being heavy oil, the markets for heavy oil are of particular relevance for us; prices for the benchmark Bow River/Hardisty stream are generally a close proxy for our average oil realizations. On a boe basis, our average price realizations were 8% higher in the first quarter of 2007, as improvements in heavy oil prices more than offset lower natural gas prices.

On March 28, 2007, the Alberta Energy and Utilities Board released Decision 2007-042 regarding ownership of coal bed methane, finding that the natural gas owner, not the coal owner, has the right to produce the natural gas stored in coal (coal bed methane). While the decision has been appealed, the finding is encouraging for the Trust, as we own the petroleum and natural gas rights on our mineral title lands in Central Alberta, which are within the primary coal bed methane fairway.

We continue to monitor the proposed income taxation changes related to income trusts. The federal government released draft legislation as part of the 2007 budget, and Bill C52 received first reading in the House of Commons on March 29, 2007. Assuming the proposed changes are enacted, the new tax will apply to Freehold starting in 2011, reducing the cash available for distribution to Unitholders. Freehold is a member of the Canadian Association of Income Funds ([www.caif.ca](http://www.caif.ca)) and part of the Coalition of Canadian Energy Trusts ([www.canadianenergytrusts.ca](http://www.canadianenergytrusts.ca)). Through these organizations, we are continuing to express our concerns and objections to the federal government regarding the proposed income trust tax changes in order to realize a better solution than what is currently being proposed. We also encourage our Unitholders to become members of the Canadian Association of Income Trust Investors ([www.caiti.info](http://www.caiti.info)). This organization has been formed with a mission to preserve the ongoing viability and sustainability of the Canadian income trust market and is an effective vehicle through which individual investors can voice their opinions regarding trust taxation.

Since inception, we have distributed \$508.3 million (\$14.75 per Trust Unit) to Unitholders. In the first quarter of 2007, Freehold declared distributions of \$22.1 million, or \$0.45 per Trust Unit, representing 78% of funds generated from operations. Production levels, commodity prices, operating costs, and other expenses remain in line with our expectations, and our distribution guidance for 2007 remains unchanged at \$1.80 per Trust Unit based on monthly distributions of \$0.15 per Trust Unit. We will continue to monitor prices and activity levels closely, and our guidance will be reviewed and updated quarterly.

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 Resources Ltd., Petrovera Resources (a general partnership), and Freehold Royalty Trust (collectively, Freehold or the Trust), for the three months ended March 31, 2007 and previous periods, and the outlook for Freehold based on information available as at May 9, 2007. The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended March 31, 2007 and March 31, 2006, 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, 2006 and 2005, together with the accompanying notes. These are on pages 13 through 49 of the Trust's 2006 annual report to Unitholders.

### FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at May 9, 2007, and contains forward-looking statements. 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, 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 Annual Information Form, which is available on our website. 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. Except as required by law, we do not undertake to update these forward-looking statements.

### CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

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 international standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

### NON-GAAP MEASURES

Within this MD&A, references are made to terms commonly used in the oil and gas industry as key performance indicators. We believe that operating income, netback, and funds generated from operations are useful supplemental measures to analyze operating performance, leverage and liquidity. 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 income, which is gross revenue less royalty expense and operating expense, represents the results of operations before general and administrative, interest, taxes and depletion, accretion and management fees. Operating netback, which is calculated as average unit sales price less royalties and operating expenses; and investor netback, which deducts administrative and interest expense and income and capital taxes, represent the cash margin for product sold, calculated on a per boe basis. Funds generated from operations 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. 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 Statement 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.

## HISTORICAL PERFORMANCE SUMMARY

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.

The acquisition of Petrovera Resources had a positive impact on our results from the date of closing on May 10, 2005. The Petrovera contribution is partially reflected in the second quarter of 2005 (52 days of production) and is fully reflected in the following periods. Another factor that has influenced our results over the past several quarters is higher operating expenses on our working interest properties, which comprise about 25% of our total production volumes. Rising costs have been experienced industry wide and particularly in Alberta where strong economic growth and oil sands development have created increased demand for people and services. However, the effect of higher costs on our overall results is mitigated by our large proportion of royalty interest production, which is unencumbered by operating expenses.

The accompanying table illustrates the fluctuations in pricing experienced over the past eight quarters and the resulting effect on our financial results.

Quarterly Review	2007	2006				2005		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
<b>Financial</b> (\$000s, except as noted)								
Revenue, net of royalty expense	34,988	31,765	36,550	36,998	33,923	43,364	42,867	27,922
Funds generated from operations	28,297	27,394	31,692	32,565	28,198	38,694	38,893	24,344
Per Trust Unit (\$)	0.58	0.56	0.65	0.66	0.58	0.79	0.79	0.59
Distributions to Unitholders	22,133	23,594	26,521	26,502	26,483	31,366	22,527	17,981
Per Trust Unit (\$) <sup>(1)</sup>	0.45	0.48	0.54	0.54	0.54	0.64	0.46	0.41
Payout ratio (%)	78	86	84	81	94	81	58	74
Net income	9,787	9,545	12,728	14,142	8,766	18,747	19,373	10,858
Per Trust Unit, basic and diluted (\$)	0.20	0.19	0.26	0.29	0.18	0.38	0.40	0.26
Property and royalty acquisitions	—	—	5,382	—	—	—	—	351,705
Capital expenditures	3,476	3,766	4,649	1,430	1,601	1,631	4,059	1,215
Long-term debt	99,000	100,000	98,000	96,000	105,000	107,000	118,000	120,000
Trust Units outstanding								
Weighted average (000s)	49,175	49,139	49,103	49,068	49,032	48,996	48,961	41,489
At quarter end (000s)	49,210	49,174	49,139	49,103	49,067	49,032	48,996	48,960
<b>Operating</b> (\$/boe, except as noted)								
Daily production (boe/d)	8,564	8,313	8,335	8,212	8,794	8,739	8,974	7,279
Average selling price	47.40	41.44	48.95	50.27	43.78	54.95	52.61	42.42
Operating netback	42.06	38.57	44.92	47.08	40.18	51.56	49.89	39.61
Operating expenses	3.33	2.95	2.75	2.43	2.68	2.38	2.03	2.54
Working Interest properties	11.82	13.86	11.88	11.51	11.26	12.06	10.35	11.00
General and administrative expenses	3.24	1.44	1.32	1.79	2.69	1.52	1.17	1.42
<b>Benchmark Prices</b>								
WTI crude oil (US\$/bbl)	58.16	60.26	70.48	70.70	63.45	60.02	63.19	53.20
Exchange rate (Cdn\$/US\$)	0.85	0.89	0.89	0.89	0.87	0.85	0.83	0.80
Edmonton Par crude oil (Cdn\$)	67.09	64.48	79.08	78.55	68.96	71.17	76.51	65.76
Light/heavy oil differential (Cdn\$/bbl)	16.98	18.80	20.14	17.43	28.57	28.14	20.79	24.17
Bow River/Hardisty (Cdn\$/bbl)	50.11	45.69	58.94	61.11	40.39	43.03	55.72	41.59
AECO natural gas (Cdn\$/Mcf)	7.45	6.36	6.03	6.27	9.27	11.68	8.17	7.38
<b>Unit Trading Performance</b>								
High (\$)	15.30	19.80	23.06	21.70	22.20	18.98	19.30	17.63
Low (\$)	13.00	12.43	18.50	18.02	18.44	15.15	15.99	14.25
Close (\$)	14.35	14.81	19.00	21.00	19.50	18.81	18.68	15.99
Volume (000s)	6,040	13,867	5,153	5,336	11,155	7,611	9,980	8,311

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

## THE ROYALTY ADVANTAGE

The following table demonstrates the advantage of our royalty lands from which we receive revenue but do not incur royalty expenses, operating expenses, site restoration expenses, or capital expenditures. Royalty interest properties accounted for 71% of gross revenue, 80% of funds generated from operations, and 91% of distributions declared during the first quarter of 2007.

<b>Components of Distributions to Unitholders</b>			
<b>Three months ended March 31, 2007</b>	Royalty Interest	Working Interest	
(\$000s)	Properties	Properties	<b>Total Trust</b>
Gross revenue	26,289	10,716	<b>37,005</b>
Royalty expense	(950)	(1,067)	<b>(2,017)</b>
Net revenue	25,339	9,649	<b>34,988</b>
Operating expense	—	(2,563)	<b>(2,563)</b>
Net operating income	25,339	7,086	<b>32,425</b>
General and administrative expense	(1,797)	(703)	<b>(2,500)</b>
Interest expense	(1,194)	(144)	<b>(1,338)</b>
Income and capital taxes	—	(145)	<b>(145)</b>
Unit based compensation	197	77	<b>274</b>
Expenditures on reclamation	—	(419)	<b>(419)</b>
Funds generated from operations	22,545	5,752	<b>28,297</b>
Reclamation fund contributions	—	302	<b>302</b>
Capital expenditures	—	(3,476)	<b>(3,476)</b>
Changes in debt	(1,000)	—	<b>(1,000)</b>
Changes in working capital	(1,442)	(548)	<b>(1,990)</b>
Distributions declared	20,103	2,030	<b>22,133</b>

## DEVELOPMENT ACTIVITIES

### ROYALTY INTEREST LANDS

Drilling on our royalty lands generally mirrors overall industry activity levels. Industry drilling declined in the first quarter of 2007, with 21% fewer wells drilled across Canada. The largest declines were in central and northern Alberta, while Saskatchewan saw increased drilling activity.

A total of 190 (4.9 equivalent net) wells were drilled on our royalty lands in the first quarter, 13% lower than last year on a gross basis, but level with last year on an equivalent net basis. There are currently 70 (3.8 equivalent net) licensed drilling locations on our royalty lands, compared with 106 (5.8 equivalent net) locations at this time last year. The lower number of drilling licences is consistent with the industry reduction.

<b>Royalty Interest Lands</b>	Three Months Ended		
	March 31		
<b>Drilling Summary</b>	2007	2006	Change
(includes unitized wells)			
Gross wells	<b>190</b>	218	-13%
Equivalent net wells <sup>(1)</sup>	<b>4.9</b>	4.9	—
Net success rate	<b>99.3%</b>	99.5%	—

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

## WORKING INTEREST PROPERTIES

About one fourth of our production comes from working interest properties on which we incur our proportionate share of development costs. Capital expenditures in the first quarter of 2007 were \$3.5 million, up from \$1.6 million last year. During the quarter, \$2.1 million was spent on drilling 17 (2.1 net) wells, with a 100% net success rate. We also spent \$1.4 million to tie-in wells drilled in the fourth quarter of 2006 and complete the Hayter facility expansion. Four (1.3 net) wells are awaiting tie-in after spring break-up.

Working Interest Properties Drilling Summary	Three Months Ended March 31			
	2007		2006	
	Gross	Net	Gross	Net
Oil	5	2.0	9	0.3
Natural gas	12	0.1	20	0.4
Other	—	—	3	0.2
<b>Total</b>	<b>17</b>	<b>2.1</b>	<b>32</b>	<b>0.9</b>

Our development program in Southeast Saskatchewan has been very successful in establishing this property as a core area for Freehold. Production in the first quarter was 420 barrels per day of light oil. Our netbacks in this area are very high: in addition to premium pricing, our production has reduced royalty expenses because we are the mineral title owner. Additional drilling locations have been identified in this area, and as a result we have increased our capital spending by \$1.5 million, which will raise our total capital budget for 2007 to \$9.5 million.

## RESULTS OF OPERATIONS

### PRODUCTION

Production volumes in the first quarter averaged 8,564 boe per day, down 3% from the first quarter of 2006. Royalty production declined 8% as drilling did not fully offset natural production declines. Working interest production rose 15% due to the success of our 2006 development program, mainly drilling successes at Hayter and Southeast Saskatchewan and the Hayter facility expansion, as well as the Wildmere acquisition completed on July 1, 2006. Royalty interests contributed 72% of total volumes produced during the quarter. On a boe basis, our production profile for the first quarter was 36% natural gas, 4% natural gas liquids (NGL), 22% light and medium oil, and 38% heavy oil.

Production levels in the second quarter are expected to be lower due to a prolonged spring break-up and annual maintenance shut-downs.

Average Daily Production	Three Months Ended March 31		
	2007	2006	Change
<b>Royalty lands</b>			
Oil (bbls/d)	3,298	3,639	-9%
NGL (bbls/d)	298	299	0%
Natural gas (Mcf/d)	15,354	16,583	-7%
Oil equivalent (boe/d)	6,155	6,702	-8%
<b>Working interest properties</b>			
Oil (bbls/d)	1,855	1,469	26%
NGL (bbls/d)	80	55	45%
Natural gas (Mcf/d)	2,841	3,411	-17%
Oil equivalent (boe/d)	2,409	2,092	15%
<b>Total Trust</b>			
Oil (bbls/d)	5,153	5,108	1%
NGL (bbls/d)	378	354	7%
Natural gas (Mcf/d)	18,195	19,994	-9%
Oil equivalent (boe/d)	8,564	8,794	-3%
Number of days in period (days)	90	90	—
Total volumes during period (Mboe)	771	791	-3%
Potash production (tonnes/d)	15.2	10.5	45%

## BENCHMARK PRICES

WTI crude oil prices were 8% lower quarter-over-quarter; however the impact was partially offset by a lower Canadian dollar. Of significance, the price spread between light and heavy oil has narrowed dramatically over the past year. Historically, differentials are the widest in the first quarter of the year, yet the spread narrowed by 41% compared with the first quarter of last year. We believe this improvement may be signalling a fundamental change in the differential, as heavy oil producers in western Canada are able to access U.S. markets via new pipelines added in 2006.

AECO natural gas prices declined 20% quarter-over-quarter on lower demand caused by the late arrival of winter weather. Longer-term, natural gas fundamentals remain positive; however, in the short term, pricing will be affected by summer cooling demands, potential hurricane activity, and industrial demand. The level of natural gas in storage remains above the five-year average although supply concerns are growing. In response to lower prices, producers are directing drilling activities away from natural gas, which will cause production to decline.

Average Benchmark Prices	Three Months Ended March 31		
	2007	2006	Change
WTI crude oil (US\$/bbl)	58.16	63.45	-8%
US\$/Cdn\$ exchange rate	0.8535	0.8662	-1%
Edmonton Par crude oil (Cdn\$/bbl)	67.09	68.96	-3%
Light/heavy oil differential (Cdn\$/bbl)	16.98	28.57	-41%
Bow River/Hardisty (Cdn\$/bbl)	50.11	40.39	24%
AECO natural gas (Cdn\$/Mcf)	7.45	9.27	-20%

Source for commodity prices: Canadian Association of Petroleum Producers.

## REALIZED PRICES

Freehold's average selling prices reflect product quality and transportation differences from benchmark prices. As approximately 38% of our total production mix is heavy oil, the markets for heavy oil are of particular relevance for us, and prices for the benchmark Bow River/Hardisty stream are generally a close proxy for our average oil realizations. On a boe basis, our average price realizations were 8% higher in the first quarter of 2007, as improvements in heavy oil prices more than offset lower natural gas prices.

Average Selling Prices	Three Months Ended March 31		
	2007	2006	Change
Oil (\$/bbl)	49.39	39.25	26%
NGL (\$/bbl)	45.02	54.65	-18%
Oil and NGL (\$/bbl)	49.09	40.25	22%
Natural gas (\$/Mcf)	7.39	8.26	-11%
Oil equivalent (\$/boe)	47.40	43.78	8%
Potash (\$/tonne)	235.15	226.56	4%

## REVENUE

Gross revenue was 6% higher in first quarter as an 8% increase in our average selling price was partially offset by a 3% decline in production volumes. Royalty expenses, including freehold mineral taxes payable to the Crown, amounted to \$2.1 million, of which \$250,000 related to 2006. (Also see Expenses, Royalties Paid.)

Revenue	Three Months Ended March 31		
	2007	2006	Change
Gross revenue	37,005	35,007	6%
Royalty expense <sup>(1)</sup>	(2,017)	(1,084)	86%
Net revenue	34,988	33,923	3%

(1) Net of Alberta Royalty Credit. Royalty expenses are incurred only on working interest production.

The accompanying table demonstrates the net effect of price and volume variances on gross revenues. "Other" includes potash revenue, sulphur revenue, lease rentals, processing fees, and interest income.

Gross Revenue Variances (\$000s)	Three Months Ended March 31	
	2007 vs. 2006	2006 vs. 2005
<b>Oil and NGL</b>		
Production increase (decrease)	306	6,074
Price increase (decrease)	4,346	139
Net increase (decrease)	4,652	6,213
<b>Natural gas</b>		
Production increase (decrease)	(1,196)	7,209
Price increase (decrease)	(1,578)	1,686
Net increase (decrease)	(2,774)	8,895
Other	120	40
<b>Gross revenue increase (decrease)</b>	<b>1,998</b>	<b>15,148</b>

## EXPENSES

### ROYALTIES PAID

Royalty expenses include all Crown charges (including freehold mineral taxes) and royalty payments to third parties. Royalty expenses increased 91% quarter-over-quarter due to timing differences in the recording of expenses, higher freehold mineral taxes, and discontinuation of the Alberta Royalty Credit program. The majority of our freehold mineral taxes, payable annually to the Crown, pertain to two sections of land in the Hayter area that were acquired in the Petrovera acquisition. Development activity on these lands has resulted in increased production and higher property values. Prior to the Petrovera acquisition, our freehold mineral taxes were not material and were recorded under working interest expenses. Freehold mineral taxes recorded the first quarter of 2007 include approximately \$250,000 that related to the 2006 tax year. In addition, freehold mineral taxes for last year were not recorded until later in 2006.

Royalty Expenses <sup>(1)</sup> (\$000s, except as noted)	Three Months Ended March 31		
	2007	2006	Change
<b>Working interest properties</b>			
Crown royalties	771	807	-4%
Alberta royalty credit <sup>(3)</sup>	—	(91)	-100%
Freehold royalties <sup>(4)</sup>	228	162	41%
Freehold mineral taxes <sup>(2)</sup>	68	89	-24%
Working interest properties	1,067	967	10%
Per boe (\$)	4.92	5.14	-4%
<b>Royalty interest lands</b>			
Crown royalties	—	—	—
Freehold royalties	—	—	—
Freehold mineral taxes <sup>(2)</sup>	950	117	712%
Royalty interest lands	950	117	712%
Per boe (\$)	1.71	0.19	800%
<b>Total royalty expenses</b>	<b>2,017</b>	<b>1,084</b>	<b>86%</b>
Per boe (\$)	<b>2.62</b>	<b>1.37</b>	<b>91%</b>

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

(2) 2006 has been restated to conform to the current presentation. Previously, freehold mineral taxes on our royalty lands were included in working interest properties, as they were not material.

(3) Effective January 1, 2007, the Alberta Government discontinued the Alberta Royalty Credit.

(4) Freehold royalties include mineral title and gross overriding royalty payments to third parties.

## OPERATING EXPENSES

Operating costs were 21% higher quarter-over-quarter, mainly due to higher working interest production volumes and inflationary pressures throughout our industry. Our large component of royalty interest production, which does not incur operating expenses, helps to shelter the Trust; however, on our working interest properties we continue to experience higher costs for services, materials, and equipment. Demand for people and services, particularly in Alberta, remains high, although lower commodity prices have reduced industry activity levels and we believe that costs are beginning to stabilize. We anticipate that our operating expenses will average approximately \$3.10 per boe in 2007.

Operating Expenses	Three Months Ended		
	March 31		
	2007	2006	Change
Working interest properties (\$000s)	2,563	2,121	21%
Per boe (\$)	11.82	11.26	5%
Royalty interest lands <sup>(1)</sup> (\$000s)	—	—	—
Per boe (\$)	—	—	—
Total operating expenses (\$000s)	2,563	2,121	21%
Total Trust (\$/boe)	3.33	2.68	24%

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

## 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 and depreciation on property, plant and equipment and accretion on the asset retirement obligation totalled \$17.7 million (\$22.96 per boe) in the first quarter of 2007, down from \$18.6 million (\$23.52 per boe) in the first quarter of 2006.

Depletion, Depreciation and Accretion Expenses	Three Months Ended		Year Ended
	March 31	March 31	December 31
	2007	2006	2006
Depletion and depreciation (\$000s)	17,626	18,557	71,874
Accretion of asset retirement obligation (\$000s)	69	62	257
Total depletion, depreciation and accretion expenses (\$000s)	17,695	18,619	72,131
Per boe (\$)	22.96	23.52	23.50

## GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

G&A costs are typically higher in the first quarter, as a number of annual expenses are paid at the start of the year. In the first quarter of 2007, G&A costs totalled \$2.5 million, including \$1.6 million charged by the Manager for time and direct costs incurred on behalf of the Trust, and \$476,000 for the Trust's share of the Manager's annual employee bonus plan for 2007. On a per boe basis, G&A expenses were 21% higher quarter-over-quarter mainly due to lower production volumes and timing differences in the recording of certain expenses.

In the first quarter, we recorded a non-cash expense of \$222,000 (with a corresponding increase to contributed surplus) as unit based compensation relating to the grant of 14,181 deferred trust units to non-management directors. The annual grant for 2006 (resulting in a non-cash expense of \$234,000 related to the issuance of 11,848 deferred trust units) was not recorded until the second quarter last year, as the plan required Unitholder approval.

In the first quarter of 2007, we also recorded a non-cash expense of \$52,000 for the Trust's proportionate share of the Manager's LTIP for 2007. At March 31, 2007, we had recorded \$570,000 as a deferred long-term compensation asset and accrued \$666,000 as a long term liability. In 2006, no amounts relating to the Manager's LTIP were recorded until the second quarter.

G&A expenses are in line with our budget, and our forecast of \$2.10 per boe for the full year remains a reasonable assumption.

G&A Expenses	Three Months Ended March 31		
	2007	2006	Change
G&A expenses (\$000s)	2,500	2,133	17%
Per boe (\$)	3.24	2.69	21%
As a percentage of revenue	7%	6%	17%

### MANAGEMENT FEES

The quarterly management fee, which is paid in Trust Units, was 35,654 Trust Units for the first quarter of 2007, unchanged from last year. The ascribed value was 26% lower due to a lower Trust Unit price at the end of the first quarter of 2007.

Management Fees (Paid in Trust Units)	Three Months Ended March 31		
	2007	2006	Change
Trust Units issued in payment of management fees	35,654	35,654	—
Ascribed value (\$000s) <sup>(1)</sup>	512	695	-26%
Per boe (\$)	0.66	0.88	-25%

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

### INTEREST EXPENSES

Interest expenses increased by \$147,000 quarter-over-quarter, due to a higher effective interest rate on our floating rate, long-term debt.

Interest Expenses (\$000s, except as noted)	Three Months Ended March 31		
	2007	2006	Change
Net interest expense	1,338	1,191	12%
Per boe (\$)	1.74	1.50	16%

### OPERATING NETBACK

Our operating netback in the first quarter of 2007 was \$42.06 per boe, up 5% mainly due to the improvement in heavy oil prices. We did not hedge any of our production 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.

Operating Netback (\$/boe)	Three Months Ended March 31		
	2007	2006	Change
Gross revenue <sup>(1)</sup>	48.01	44.23	9%
Royalty expenses <sup>(2)</sup>	(2.62)	(1.37)	91%
Operating expenses	(3.33)	(2.68)	24%
Operating netback	42.06	40.18	5%

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

(2) Net of Alberta Royalty Credit in 2006.

## FUNDS GENERATED FROM OPERATIONS AND NET INCOME

Funds generated from operations were flat quarter-over-quarter, while net income improved by \$1.0 million. Higher capital expenditures in 2006 resulted in an increase in the future income taxes. Expenditures on reclamation were also higher than the first quarter last year.

Funds Generated From Operations and Net Income	Three Months Ended March 31		
	2007	2006	Change
Funds generated from operations (\$000s)	28,297	28,198	—
Per Trust Unit (\$)	0.58	0.58	—
Net income (\$000s)	9,787	8,766	12%
Per Trust Unit, basic and diluted (\$)	0.20	0.18	11%

## DISTRIBUTIONS

Distributions to Unitholders totalled \$0.45 per Trust Unit for the first quarter. Royalty income contributed 91% of distributions for the quarter. Since inception, the Trust has distributed \$508.3 million (\$14.75 per Trust Unit) to Unitholders.

Distributions to Unitholders (\$000s, except as noted)	Three Months Ended March 31	
	2007	2006
Cash provided by operating activities	26,483	33,170
Net reclamation fund contribution	302	(105)
Capital expenditures	(3,476)	(1,601)
Debt additions (repayment)	(1,000)	(2,000)
<b>Cash available for distribution</b>	<b>22,309</b>	<b>29,464</b>
<b>Distributions to Unitholders</b>	<b>22,133</b>	<b>26,483</b>
Accumulated, beginning of period	486,124	383,024
Accumulated, end of period	508,257	409,507
<b>Distributions per Trust Unit (\$) <sup>(1)</sup></b>	<b>0.45</b>	<b>0.54</b>
Accumulated, beginning of period	14.30	12.20
Accumulated, end of period	14.75	12.74

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

Cash available for distribution is typically less than cash provided by operating activities as we retain funds to finance reclamation fund contributions, capital expenditures, minor acquisitions, and debt repayment. Differences between cash available for distribution and actual distributions result from changes in working capital. First quarter distributions represented 78% of funds generated from operations, versus 94% in the first quarter of 2006. Since inception, our payout ratio has averaged 82%.

Payout Ratio <sup>(1)</sup> (\$ per Trust Unit, except as noted)	Three Months Ended March 31		
	2007	2006	Change
Funds generated from operations	28,297	28,198	—
Distributions to Unitholders	22,133	26,483	-16%
Payout ratio <sup>(1)</sup>	78%	94%	-17%

(1) Distributions to Unitholders as a percentage of funds generated from operations.

## DISTRIBUTION OUTLOOK

Based on the assumptions provided in the accompanying table, our distribution guidance for 2007 remains unchanged at \$1.80 per Trust Unit, with monthly distributions of \$0.15 per Trust Unit. Recognizing the cyclical nature of our industry, we caution that significant changes in production rates, commodity prices, interest rates, or foreign exchange rates (positive or negative) will result in adjustments to the distribution level. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as approximately 38% of our total boe production is heavy oil. We will continue to monitor prices and activity levels closely, and our guidance will be reviewed and updated quarterly.

<b>2007 Distribution Outlook and Key Assumptions</b>	<b>May 9 2007</b>	February 28 2007
<b>Estimated cash distributions (\$ per Trust Unit)</b>	<b>1.80</b>	1.80
<b>Key assumptions:</b>		
Average daily production, excluding acquisitions (boe/d)	<b>7,950</b>	7,950
Average WTI oil price (US\$/bbl)	<b>61.50</b>	62.50
Average Bow River Hardisty oil price (Cdn\$/bbl)	<b>45.00</b>	43.30
Average AECO natural gas price (Cdn\$/Mcf)	<b>7.25</b>	7.25
Average light/heavy oil price differential (Cdn\$/bbl)	<b>23.00</b>	25.00
Average exchange rate (Cdn\$/US\$)	<b>0.90</b>	0.90
Average operating costs (\$/boe)	<b>3.10</b>	3.00
Average general and administrative costs (\$/boe)	<b>2.10</b>	2.10
Capital expenditures (\$ millions)	<b>9.5</b>	8.0
Long-term debt at year end (\$ millions)	<b>97</b>	97
Weighted average Trust Units outstanding (thousands)	<b>49,228</b>	49,228
Payout ratio (%)	<b>86</b>	89
Estimated portion of distributions taxable as income (%)	<b>100</b>	100

We continue to monitor the proposed income taxation changes related to income trusts. The federal government released draft legislation as part of the 2007 budget, and Bill C52 received first reading in the House of Commons on March 29, 2007. Assuming the proposed changes are enacted, the new tax will apply to Freehold starting in 2011, reducing the cash available for distribution to unitholders.

## FOREIGN OWNERSHIP UPDATE

Our Trust Indenture provides that not more than 49% of the Trust's Units can be held by non-residents. We monitor foreign ownership levels on a regular basis through declarations from Unitholders and geographical searches. Based on geographical data as of March 21, 2007 (the record date for our 2007 annual meeting of Unitholders), we estimate that approximately 83% of the Trust's Units are held by Canadian residents, with the remaining 17% held by non-residents. While we believe that these results are reasonable estimations, the inability of all public issuers to obtain the residency information of their beneficial holders means that issuers must rely upon the information provided to the transfer agent. As a result, the residency information is subject to the accuracy provided by third party data and by system limitations. Accordingly, the reported level of Canadian ownership is subject to these limitations, and the level of Canadian ownership can change at any time without notice.

## LIQUIDITY AND CAPITAL RESOURCES

We currently have \$66 million of available capacity under our credit facilities. During the last 12 months, we have repaid \$6 million of long-term debt with funds generated from operations. At March 31, 2007, we had no short-term debt outstanding and long-term debt was \$99 million. We had positive working capital of \$11.0 million, resulting in net debt of \$88.0 million.

Debt Analysis (\$000s)	March 31		December 31
	2007	2006	2006
Long-term debt	99,000	105,000	100,000
Short-term debt	—	—	—
Total debt	99,000	105,000	100,000
Less: working capital	11,042	14,289	9,050
Net debt obligations	87,958	90,711	90,950

Our financial leverage and coverage ratios remain among the best in the energy trust sector, reflecting the Trust's healthy financial condition. At March 31, 2007, the Trust's ratio of net debt (total debt less positive working capital) to trailing funds generated from operations was 0.7 to 1, unchanged from the first quarter last year.

Financial Leverage and Coverage Ratios <sup>(1)</sup>	March 31		December 31
	2007	2006	2006
Net debt to funds generated from operations (times)	0.7	0.7	0.8
Net debt to distributions (times)	0.9	0.9	0.9
Distributions to interest expense (times)	18.5	24.0	19.9
Net debt to net debt plus equity (%)	21%	19%	21%

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

The following table outlines our sources and uses of funds in the first quarters of 2007 and 2006.

Sources and Uses of Funds (\$000s)	Three Months Ended March 31		
	2007	2006	Change
<b>Sources of funds</b>			
Funds generated from operations	28,297	28,198	—
Change in non-cash working capital	(1,739)	5,754	-130%
	26,558	33,952	-22%
<b>Uses of funds</b>			
Debt reduction (addition)	1,000	2,000	-50%
Net reclamation fund contributions (reduction)	(302)	105	-388%
Development expenditures	3,476	1,601	117%
Distributions paid	22,128	30,400	-27%
Change in cash	256	(154)	-266%
	26,558	33,952	-22%

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

Components of Working Capital (\$000s)	Mar. 31 2007	Dec. 31 2006	Sept. 30 2006	June 30 2006	Mar. 31 2006
Cash	677	421	585	245	38
Accounts receivable	27,870	29,850	28,311	28,051	32,125
Current assets	28,547	30,271	28,896	28,296	32,163
Distributions payable to Unitholders	(7,381)	(7,376)	(8,845)	(8,839)	(8,832)
Accounts payable and accrued liabilities	(10,124)	(13,845)	(12,498)	(9,107)	(9,042)
Current liabilities	(17,505)	(21,221)	(21,343)	(17,946)	(17,874)
Working capital <sup>(1)</sup>	11,042	9,050	7,553	10,350	14,289

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

## TRUST UNITS OUTSTANDING

As at March 31, 2007 and May 9, 2007, there were 49,209,851 Trust Units outstanding. At the end of the first quarter, the Trust issued 35,654 Trust Units to the Manager in payment of the quarterly management fee.

On January 1, 2007, the Board granted 14,181 deferred trust units to eligible directors of Freehold Resources Ltd. as part of the directors' annual compensation. Each eligible director received 2,026 deferred trust units, and the Chair of the Board received 4,051 deferred trust units. As at March 31, 2007 there were 27,609 deferred trust units outstanding and at May 9, 2007, there were 27,902 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

Trust Units Outstanding	Three Months Ended		
	March 31		
	2007	2006	Change
Weighted average			
Basic	49,174,593	49,031,977	—
Diluted	49,201,773	49,031,977	—
At period end	49,209,851	49,067,235	—

### 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.

The Trust has no operational control over its royalty lands, as it primarily holds small royalty interests in several thousand wells. Obtaining timely production data from the well operators is extremely difficult. Thus, we use government reporting databases and past production receipts to estimate revenue accruals. The substantial increase in royalty interest production with the Petrovera acquisition in May 2005 required a corresponding increase in our revenue accruals. The increase is reflected in higher accounts receivables.

### CHANGES IN ACCOUNTING POLICIES

On January 1, 2007, the Trust adopted the new Canadian accounting standards for financial instruments - recognition and measurement, hedging and comprehensive income. The new standards require all financial instruments within their scope, including all derivatives, to be recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available-for-sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in earnings. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to earnings when derecognized or impaired.

Cash and short-term investments, if any, are held-to-maturity investments and the fair values approximate their carrying value due to their short-term nature. Accounts receivable and accounts payable and accrued liabilities are classified as loans and receivables and the fair values approximate their carrying value due to the short-term nature of these instruments. The Trust has not designated any financial instruments as available-for-sale or held-for-trading.

On adoption, the Trust elected to recognize, as separate assets and liabilities, only for those embedded derivatives in hybrid instruments issued, acquired or substantively modified after January 1, 2003. The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

## ENVIRONMENTAL REGULATION AND RISK

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation under a variety of federal, provincial, and local laws and regulations. Compliance with these regulations can require significant expenditures and a breach may result in fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs. In 2002, the Government of Canada ratified the Kyoto Protocol, which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate about Canada's ability to meet these targets and the Government's strategy or alternative strategies on climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases, whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Trust.

On April 26, 2007, the Federal Government released its *Action Plan to Reduce Greenhouse Gases and Air Pollution*, also known as ecoACTION, which includes the Regulatory Framework for Air Emissions. The plan covers not only large industry, but also regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects, ecoAction is intended to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) a 50% reduction in air pollution from industry by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. To facilitate compliance with the plan's requirements, while at the same time allowing companies to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

On March 8, 2007, the Alberta Government introduced Bill 3, the *Climate Change and Emissions Management Amendment Act*, which intends to reduce greenhouse gas emission intensity from large industries. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12% starting July 1, 2007; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay \$15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. Alternatively, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf provided that these projects are based in Alberta. Prior to investing, the offset reductions offered by a prospective operation must be verified by a third party to ensure that the emission reductions are real.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact of those requirements on the Trust and its operations and financial condition.

## REVIEW OF ALBERTA ROYALTY AND TAX REGIME

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral taxes) pertaining to oil and gas resources, including oil sands, conventional oil and gas, and coalbed methane, will be conducted by a panel of experts with the assistance of individual Albertans and key stakeholders. The review panel is to produce a final report that will be presented to the Minister of Finance by August 31, 2007.

## ADDITIONAL INFORMATION

Additional information about Freehold, including our annual information form, is available on SEDAR at [www.sedar.com](http://www.sedar.com).

## Consolidated Balance Sheets

(\$000s) (unaudited)	March 31, 2007	December 31, 2006
<b>Assets</b>		
Current assets:		
Cash	\$ 677	\$ 421
Accounts receivable	27,870	29,850
	<b>28,547</b>	<b>30,271</b>
Reclamation fund	1,815	2,117
Deferred long-term compensation (note 4)	570	86
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$327,357 (2006 - \$309,731)	427,673	441,754
	<b>\$ 458,605</b>	<b>\$ 474,228</b>
<b>Liabilities and Unitholders' Equity</b>		
Current liabilities:		
Distributions payable to Unitholders	\$ 7,381	\$ 7,376
Accounts payable and accrued liabilities	10,124	13,845
	<b>17,505</b>	<b>21,221</b>
Asset retirement obligations (note 5)	4,318	4,598
Unit based compensation payable (note 4)	666	129
Long-term debt (note 2)	99,000	100,000
Future income tax liability	4,280	3,832
Unitholders' equity:		
Unitholders' capital (note 3)	563,210	562,698
Contributed surplus (note 4)	469	247
Deficit	(230,843)	(218,497)
	<b>332,836</b>	<b>344,448</b>
	<b>\$ 458,605</b>	<b>\$ 474,228</b>

See accompanying notes to interim consolidated financial statements.

## Consolidated Statements of Income and Deficit and Comprehensive Income

(Unaudited) (\$000s, except per unit and weighted average data)	Three Months Ended March 31	
	2007	2006
Revenue:		
Royalty income and working interest sales	\$ 37,005	\$ 35,007
Royalty expense (net of Alberta Royalty Tax Credit)	(2,017)	(1,084)
	<b>34,988</b>	<b>33,923</b>
Expenses:		
Operating	2,563	2,121
General and administrative	2,500	2,133
Interest on long-term debt	1,338	1,191
Depletion and depreciation	17,626	18,557
Accretion of asset retirement obligation	69	62
Management fee	512	695
	<b>24,608</b>	<b>24,759</b>
Net income before taxes	10,380	9,164
Income and capital taxes	145	276
Future income tax provision	448	122
	<b>593</b>	<b>398</b>
Net income and comprehensive income	\$ 9,787	\$ 8,766
Deficit, beginning of period	(218,497)	(160,578)
Distributions declared	(22,133)	(26,483)
Deficit, end of period	\$ (230,843)	\$ (178,295)
Net income per Trust Unit, basic and diluted	<b>\$ 0.20</b>	<b>\$ 0.18</b>
Weighted average number of Trust Units:		
Basic	49,174,593	49,031,977
Diluted	<b>49,201,773</b>	<b>49,031,977</b>

See accompanying notes to interim consolidated financial statements.

## Consolidated Statements of Cash Flows

(Unaudited) (\$000s)	Three Months Ended March 31	
	2007	2006
Cash provided by (used in):		
Operating:		
Net income	\$ 9,787	\$ 8,766
Items not involving cash:		
Depletion and depreciation	17,626	18,557
Trust Unit incentive compensation (note 4)	274	—
Future income tax provision	448	122
Accretion of asset retirement obligation	69	62
Trust Units issued in lieu of management fee	512	695
Expenditures on reclamation	(419)	(4)
	28,297	28,198
Changes in non-cash working capital	(1,814)	4,972
	26,483	33,170
Financing:		
Long-term debt	(1,000)	(2,000)
Distributions paid	(22,128)	(30,400)
Changes in non-cash working capital	30	(175)
	(23,098)	(32,575)
Investing:		
Capital expenditures	(3,476)	(1,601)
Change in reclamation fund	302	(105)
Changes in non-cash working capital	45	957
	(3,129)	(749)
Increase (decrease) in cash	256	(154)
Cash, beginning of period	421	192
Cash, end of period	\$ 677	\$ 38

See accompanying notes to interim consolidated financial statements.

## Notes to Interim Consolidated Financial Statements

For the period ended March 31, 2007.

### 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, 2006, except for the new standards regarding financial instruments detailed below. The following disclosure is incremental to the disclosure contained in the notes to the 2006 annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes for the year ended December 31, 2006.

Two new Canadian accounting standards have been issued that will require additional disclosure in the Trust's financial statements commencing January 1, 2008, regarding financial instruments, as well as capital and how it is managed.

#### CHANGES IN ACCOUNTING POLICIES

On January 1, 2007, the Trust adopted the new Canadian accounting standards for financial instruments—recognition and measurement, hedging and comprehensive income. The new standards require all financial instruments within their scope, including all derivatives, to be recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available-for-sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in earnings. Available-for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to earnings when derecognized or impaired.

Cash and short-term investments, if any, are held-to-maturity investments and the fair values approximate their carrying value due to their short-term nature. Accounts receivable and accounts payable and accrued liabilities are classified as loans and receivables and the fair values approximate their carrying value due to the short-term nature of these instruments. The Trust has not designated any financial instruments as available-for-sale or held-for-trading.

On adoption, the Trust elected to recognize, as separate assets and liabilities, only for those embedded derivatives in hybrid instruments issued, acquired or substantively modified after January 1, 2003. The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

### 2. LONG-TERM DEBT

Freehold has a \$150 million extendible revolving term credit facility, extendible annually, on which \$99 million was drawn at March 31, 2007. In the event that the lender does 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 2007. In addition, Freehold has available 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, ranging from 85 to 140 basis points and standby fees. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets. In April 2007 the lender agreed to extend the terms of the agreement until May 2008.

### 3. UNITHOLDERS' CAPITAL

	March 31, 2007		December 31, 2006	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	49,174,197	562,698	49,031,581	560,049
Issued in lieu of management fee	35,654	512	142,616	2,649
Balance, end of period	49,209,851	563,210	49,174,197	562,698

### 4. UNIT BASED COMPENSATION

#### (a) 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 of the date of distribution. As at March 31, 2007, there were 27,609 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

	March 31, 2007	December 31, 2006
<b>Deferred Trust Units</b>		
Balance, beginning of period	12,559	—
Annual grant	14,181	11,165
Additional units resulting from distributions	869	1,394
Balance, end of period	27,609	12,559

For the three month period ended March 31, 2007, the Trust expensed \$222,000 as unit based compensation, with a corresponding increase to contributed surplus.

	March 31, 2007	December 31, 2006
<b>Contributed Surplus (\$000s)</b>		
Balance, beginning of period	247	—
Trust Unit incentive compensation expense	222	247
Balance, end of period	469	247

#### (b) 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 made by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. At March 31, 2007, the Trust had recorded \$570,000 as a deferred long-term compensation asset and accrued \$666,000 as a long-term liability, expensing \$52,000 for the three month period then ended.

### 5. ASSET RETIREMENT OBLIGATIONS

Freehold has no asset retirement obligations on its royalty income properties. Freehold's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of Freehold's total asset retirement obligation is estimated to be \$4.3 million (discounted at a weighted average, credit adjusted, risk free rate of 6.1%), the undiscounted value of which is \$11.8 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being over 15 years away.

	March 31, 2007	December 31, 2006
<b>Asset Retirement Obligations (\$000s)</b>		
Balance, beginning of period	4,598	4,036
Liabilities incurred	70	364
Liabilities settled	(419)	(302)
Revisions in estimates	—	243
Accretion expense	69	257
Balance, end of period	4,318	4,598

## 6. RELATED PARTY TRANSACTIONS

For the three month period ended March 31, 2007, Freehold issued 35,654 Trust Units as management fee to the Manager (2006 – 35,654 Trust Units).

For the three month period ended March 31, 2007, the Manager charged the Trust \$1.6 million in general and administrative costs (2006 - \$1.5 million). At March 31, 2007, there was \$1.1 million in accounts payable relating to these costs.

## 7. SUPPLEMENTAL CASH FLOW DISCLOSURE

Cash Expenses Paid (\$000s)	Three Months Ended March 31	
	2007	2006
Interest	1,308	1,367
Taxes	278	390

## Corporate Information

### BOARD OF DIRECTORS

**William W. Siebens** <sup>(2)</sup>  
President and Chief Executive Officer  
Candor Investments Ltd.

**D. Nolan Blades** <sup>(1)(2)(3)(4)</sup>  
President  
Sunny Gables Holdings Ltd.

**Harry S. Campbell, Q.C.** <sup>(3)(4)</sup>  
Managing Partner  
Burnet, Duckworth & Palmer, LLP

**Tullio Cedraschi**  
President and Chief Executive Officer  
CN Investment Division

**Peter T. Harrison** <sup>(1)(3)(4)</sup>  
Senior Vice-President  
Montrusco Bolton Investments Inc.

**Dr. P. Michael Maher** <sup>(1)(2)(4)</sup>  
Professor, Haskayne School of Business  
University of Calgary

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

- (1) Audit Committee
- (2) Governance Committee
- (3) Reserves Committee
- (4) Compensation Committee

### 2007 FIRST QUARTER DISTRIBUTIONS DECLARED

Record Date	Payment Date	Per Trust Unit
January 31, 2007	February 15, 2007	\$0.15
February 28, 2007	March 15, 2007	\$0.15
March 31, 2007	April 15, 2007	<u>\$0.15</u>
		<u>\$0.45</u>

### TAX INFORMATION AND HISTORICAL DISTRIBUTIONS

Tax information and historical distributions are available on our website at [www.freeholdtrust.com](http://www.freeholdtrust.com).

### OFFICERS

**William W. Siebens**  
Chair of the Board

**David J. Sandmeyer**  
President and Chief Executive Officer

**J. Frank George**  
Vice-President, Exploitation

**Darren G. Gunderson**  
Controller

**Joseph N. Holowisky**  
Vice-President, Finance & Administration  
Chief Financial Officer and Secretary

**William O. Ingram**  
Vice-President, Production

**Michael J. Okrusko**  
Vice-President, Land

### HEAD OFFICE

**Freehold Resources Ltd.**  
**Freehold Royalty Trust**  
400, 144 – 4th Avenue S.W.  
Calgary, Alberta T2P 3N4  
Telephone: (403) 221-0802  
Fax: (403) 221-0888

### INVESTOR RELATIONS CONTACT

**Karen C. Taylor**  
Manager, Investor Relations  
Telephone: (403) 221-0891  
Toll Free: 1-888-257-1873  
Email: [ir@freeholdtrust.com](mailto:ir@freeholdtrust.com)

### WEBSITE

[www.freeholdtrust.com](http://www.freeholdtrust.com)

### STOCK EXCHANGE LISTING

**Toronto Stock Exchange**  
Trading Symbol: FRU.UN

### 2007 FIRST QUARTER TRADING SUMMARY

High – \$15.30  
Low – \$13.00  
Close – \$14.35  
Volume – 6,040,179  
Trust Units Outstanding – 49.2 million  
Mar. 31 Market Capitalization – \$706 million

### 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](mailto:service@computershare.com)

### 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

### RESERVE EVALUATORS

Trimble Engineering Associates Ltd.  
Calgary, Alberta