

Quarterly Report

THREE AND TWELVE MONTHS ENDED DECEMBER 31, 2009

Freehold Royalty Trust Announces
2009 Fourth Quarter Results and Year-End Reserves

RESULTS AT A GLANCE Financial (\$000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	Change	2009	2008	Change
Gross revenue	35,167	34,461	2%	119,965	204,116	-41%
Net income	14,721	13,374	10%	31,741	109,956	-71%
Per Trust Unit, basic and diluted (\$)	0.29	0.27	6%	0.63	2.23	-72%
Cash provided by operating activities	25,937	41,672	-38%	95,659	179,252	-47%
Per Trust Unit (\$)	0.50	0.84	-40%	1.91	3.63	-47%
Funds generated from operations (1)	30,444	26,942	13%	95,085	171,282	-44%
Per Trust Unit (\$)	0.59	0.55	7%	1.90	3.47	-45%
Capital expenditures	4,435	3,770	18%	15,491	12,992	19%
Property and royalty acquisitions (net)	9,539	(782)	1320%	9,539	7,693	24%
Distributions declared	23,937	54,387	-56%	70,480	143,749	-51%
Per Trust Unit (\$) (2)	0.46	1.10	-58%	1.40	2.91	-52%
Long-term debt, period end	45,000	140,000	-68%	45,000	140,000	-68%
Unitholders' equity, period end	298,972	220,005	36%	298,972	220,005	36%
Trust Units (000s) (3)	51,483	49,424	4%	50,000	49,371	1%
Operating						
Average daily production (boe/d) (4)	7,402	7,779	-5%	7,302	7,804	-6%
Average price realizations (\$/boe) (4)	51.09	46.55	10%	44.00	69.93	-37%
Operating netback (\$/boe) (1) (4) (5)	45.66	42.14	8%	39.61	65.18	-39%

(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)".

(5) Excludes other income.

DISTRIBUTION

The Board of Directors has declared the March distribution of \$0.14 per Trust Unit which will be paid on April 15, 2010 to Unitholders of record on March 31, 2010 (ex-distribution date March 29, 2010). Including the April 15 payment, our 12-month trailing cash distributions total \$1.52 per Trust Unit. The regular monthly distribution will remain fixed at \$0.14 per Trust Unit until further notice.

Message to Unitholders

Our results for the fourth quarter reflect improved oil prices which, together with our oil-weighted product mix and the low cost structure of our royalty production, combined to deliver strong netbacks. Fourth quarter production volumes were down 5%, mainly due to a lack of drilling activity on our royalty lands during 2009.

In December, we improved our already strong balance sheet with an equity offering, issuing 7.6 million Trust Units at \$15.15 per Trust Unit. This was only our third equity offering in 13 years, and we were pleased by the market's response and by the confidence demonstrated not only by the participation of our largest Unitholder, CN Pension Trust Funds, but also by the underwriters' exercise of the full 15% over-allotment option. Net proceeds of \$110.5 million were used, initially, to reduce long-term debt and, subsequently to fund \$49 million in royalty acquisitions.

CRUDE OIL AND NATURAL GAS MARKETS

Overall, the outlook for crude oil is more favourable than for natural gas. Markets for heavy oil remain robust due to strong refinery demand for this product type. Winter weather has increased heating demand throughout North America, and natural gas markets have responded with modest price increases. Although these factors are positive in the short-term, we believe that the road to full economic recovery will be long and bumpy, with continued commodity price volatility. The commodity price fluctuations of the past 18 months serve to reinforce that our cash flows, and thus our distributions, are largely dependant on cyclical supply and demand factors that are beyond our control.

ROYALTY LANDS AND INDUSTRY ACTIVITY

Industry activity levels in the final three months of the year remained muted compared to 2008 with fewer than 1,800 wells drilled in western Canada. Industry drilled 55% fewer wells overall in 2009 than in 2008, and the average utilization rate for Canadian drilling rigs was at an all time low of 26%. As expected, drilling on our royalty lands in 2009 reflected the overall decline in industry activity levels; however, at year-end, there were 86 licensed drilling locations on our royalty lands, up from 64 locations at the end of 2008.

The Petroleum Services Association of Canada recently updated its 2010 Canadian drilling activity forecast and is "cautiously optimistic" that commodity prices will strengthen further in 2010, leading to increased drilling activity. The Alberta Government's short-term stimulus plan to encourage conventional oil and natural gas activity in the province is also expected to have a positive impact on industry activity levels in the coming months. While operators may focus on opportunities on Crown lands to take advantage of the incentives, we anticipate that increased activity will be eventually reflected on our royalty lands.

ROYALTY ACQUISITIONS

On December 21, 2009, we completed a royalty acquisition for \$10 million after closing adjustments, expanding our presence in the multi-zone prospective deep basin region of Northwest Alberta. We acquired royalty interests on 43,214 gross acres, of which 26,400 are located in the Bigstone area of Northwest Alberta and represent the creation of a 5% overriding royalty interest. The agreement provides for a drilling contribution by Freehold of up to \$1.9 million over the next five years to assist the vendor in the development of undeveloped lands in the Bigstone area. Future opportunities on the Bigstone lands include natural gas and shallow Cardium oil. The remaining lands (16,814 gross acres) represent the assignment to Freehold of gross overriding royalties of varying percentages of production in 12 properties in Alberta and British Columbia. Current production consists of primarily liquids rich, sweet natural gas from 15 gross wells. Reserves were independently evaluated at 0.3 MMBoe net proved plus probable, effective December 31, 2009, and have an estimated reserve life index of six years based on annualized 2010 production of 145 boe per day.

Subsequent to year-end, we acquired royalty interests on 319,681 gross acres in Alberta, Saskatchewan, and British Columbia, for \$39 million, after closing adjustments. The acquisition represents the creation of a 5% overriding royalty interest on 11 producing properties and the assignment to Freehold of eight small gross overriding royalty interests. Current production is 60% natural gas from 600 gross wells. Reserves were independently evaluated at 1.4 MMBoe net proved plus probable, and have an estimated reserve life index of just under nine years. These reserves are not

included in our December 31, 2009 reserve update. The acquisition closed on February 17, 2010 and is expected to add 380 boe per day to 2010 production. We anticipate further development on these lands over the next several years.

Both acquisitions support our strategy of focusing on oil and gas royalties and are accretive, on a debt-adjusted per unit basis, to cash flow, production, reserves, and net asset value. The creation of overriding royalties provides benefits to both parties. For the vendors, the sale proceeds provide a source of capital to fund their ongoing development activities. For Freehold, the acquired royalty interests bring strong netbacks, as production is unencumbered by operating and capital costs and third party royalty expenses. The acquisitions also allow us to benefit from future development on the properties.

With additional production from these two royalty acquisitions, we are increasing our production estimate for 2010 by 9% to 7,600 boe per day. Royalties are expected to account for 70% of this production.

WORKING INTEREST PROPERTIES

In the fourth quarter of 2009, we participated in the drilling of three (1.2 net) Bakken wells. One (0.5 net) well was a stratigraphic test and considered dry and abandoned; the other two (0.7 net) wells came on production in December. Since 2005, we have participated in the drilling of 28 (7.7 net) Bakken wells on our lands.

Our first two 100% wells on our Bakken oil-prone lands in Southeast Saskatchewan, drilled in the third quarter of 2009, commenced production in November, and each averaged 80 barrels per day in December.

Our \$24 million capital budget for 2010 represents a substantial increase over 2009, as we plan to follow up on our success in Southeast Saskatchewan with 15 (6.5 net) wells. In addition, we anticipate an active program at Pembina Cardium Unit #9 as the operator, Penn West, continues with field redevelopment using horizontal infill drilling and multi-stage fracture stimulation.

LAND AND RESERVES UPDATE

At December 31, 2009, our land holdings encompassed just under 2.4 million gross acres, over 90% of which are royalty interests. Proved plus probable reserves totalled 24.1 million barrels of oil equivalent (MMboe), with reserves assigned to 22,929 wells. Royalty interest reserves declined 7.3% year-over-year, while working interest reserves increased 2.4%.

In 2009, we spent \$25.0 million on development activities and acquisitions, adding 1.4 MMboe of net proved plus probable reserves. We replaced approximately 50% of 2009 production at an all-in finding, development and acquisition (FD&A) cost of \$18.86 per boe (including changes in future development capital). These activities resulted in a one-year recycle ratio of 2.1 times the capital invested, and a three-year average recycle ratio of 1.9 times.

On a boe basis, our reserves profile was 38% natural gas, 34% heavy oil, 23% light and medium oil, and 5% natural gas liquids (NGL). Approximately 63% of our reserves are in the proved category, and 99% of our proved reserves are producing, which is high by industry standards. Our reserve life index (RLI) for proved plus probable reserves at the end of 2009 was 9.7 years, compared with 9.8 years at the end of 2008.

Based on the independent evaluation of our reserves as at December 31, 2009, the present value of our net proved plus probable oil and gas reserves (discounted at 10%, before tax), was \$707.6 million, down slightly from \$730.7 million at the end of 2008. Our undeveloped land was independently valued at \$79.4 million, down from \$94.0 million at year-end 2008, due to lower average land sale prices during 2009. Our net asset value was \$13.06 per Trust Unit, compared with \$13.92 per Trust Unit at year-end 2008.

SIFT TAX STRATEGY UPDATE

We have always maintained that Freehold, with its large, diversified asset base of primarily royalty interests, low risk profile, low sustaining capital requirements, and high payout ratio, is ideally suited to the income trust structure. However, with the new tax on income trusts beginning in 2011, we are evaluating alternative structures. Last year, our Board established a special committee of independent directors and charged them with a mandate to determine a course of action that best maximizes Unitholder value. While a clear direction has not yet been determined, the committee has been examining the structures that our peers are adopting, assessing overall market sentiment, and considering complex legal and tax issues, including implications with respect to future access to capital.

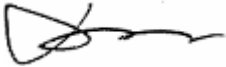
The assets we acquired with the \$264 million proceeds of our Initial Public Offering in November 1996 have performed very well over the past 13 years, supported by an experienced management team who have managed those assets for more than a quarter century. We have augmented our holdings over the years with complementary acquisitions, resulting in an overall asset value of \$13.06 per Trust Unit at December 31, 2009. During this period, we declared distributions of \$20.53 per Trust Unit, more than double the IPO price of \$10.00.

MANAGEMENT

In our third quarter report, we announced that Michael Okrusko, will retire at the end of this year, after serving for more than 28 years with Rife Resources, the Manager of the Trust. To facilitate succession planning, the Board is pleased to announce the appointment of Michael Okrusko as Senior Vice-President, Special Projects, and the appointment of Michael Stone as Vice-President, Land, effective March 1, 2010.

In closing, we note with profound sadness the passing of Joe Holowisky on February 20, 2010, after a 22-year battle with heart disease. Joe was Freehold's CFO for 13 years, until his retirement in January 2009, and was a vital member of Rife's management team for more than 27 years. He will be deeply missed by his wife, Dianne, and his children Todd and Gillian, as well as his Rife and Freehold families.

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



William O. Ingram
President and Chief Executive Officer

Summary of Reserves

Our oil and natural gas reserves were independently evaluated by Trimble Engineering Associates Ltd. (Trimble) as at December 31, 2009. The evaluation was conducted in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in National Instrument 51-101 (NI 51-101).

Our Reserves Committee met with Trimble to review the findings and procedures, and the reserves report has been accepted by our Board. A summary of net reserves, on a before-tax basis, is provided below. Complete NI 51-101 reserves disclosure, including after-tax reserve values, reserves by major property, and abandonment costs, are included in our annual information form (AIF), which will be filed on SEDAR later this month.

The reserves data below is presented on a net basis (our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands). Freehold is unique in that the majority of our assets are royalty interests. However, under NI 51-101, royalty interests cannot be included under gross reserves. This causes our gross reserves to be lower than our net reserves and makes it difficult for investors to compare our reserves to others in our industry. We believe the most appropriate measure of reserves for Freehold is net reserves.

OIL AND GAS RESERVES AS AT DECEMBER 31, 2009 ⁽¹⁾	Light and Medium Crude Oil		Heavy Crude Oil		Total Crude Oil	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)
Reserves Category						
Proved developed producing	1,673	3,520	1,042	4,806	2,715	8,326
Proved developed non-producing	88	77	-	-	88	77
Proved undeveloped	-	-	-	83	-	83
Total proved	1,761	3,596	1,042	4,889	2,803	8,485
Probable	1,000	1,974	717	3,270	1,717	5,244
Total proved plus probable	2,761	5,571	1,759	8,159	4,520	13,730

Reserves Category	Natural Gas		Natural Gas Liquids		Oil Equivalent ⁽⁴⁾	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
	(MMcf)	(MMcf)	(Mbbbl)	(Mbbbl)	(Mboe)	(Mboe)
Proved developed producing	4,782	35,428	179	824	3,690	15,055
Proved developed non-producing	15	15	-	-	90	79
Proved undeveloped	-	113	-	-	-	102
Total proved	4,796	35,555	179	824	3,780	15,236
Probable	2,889	19,060	89	398	2,287	8,818
Total proved plus probable	7,685	54,615	268	1,222	6,068	24,054

(1) Numbers may not add due to rounding.

(2) Gross reserves are our share of working interest properties before deduction of royalties payable to others. Gross reserves exclude royalty interests.

(3) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands.

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

RECONCILIATION OF NET OIL AND GAS RESERVES BY PRINCIPAL PRODUCT TYPE ^{(1) (2)}	Light and	Heavy	Total	Natural	Associated	Oil
	Medium Crude Oil (Mbbbls)	Crude Oil (Mbbbls)	Crude Oil (Mbbbls)	Gas Liquids (Mbbbls)	Gas (MMcf)	Equivalent ⁽⁴⁾ (Mboe)
Proved Producing						
December 31, 2008	3,839	5,311	9,150	815	38,132	16,321
Extensions	203	266	469	17	732	608
Improved recovery	-	-	-	-	-	-
Technical revisions	18	216	234	117	1,822	655
Discoveries	-	-	-	-	-	-
Acquisitions	7	5	12	21	1,065	211
Dispositions	-	-	-	-	-	-
Economic factors	(10)	(7)	(17)	-	93	(2)
Production ⁽³⁾	(537)	(985)	(1,522)	(146)	(6,415)	(2,737)
December 31, 2009	3,520	4,806	8,326	824	35,428	15,055
Total Proved						
December 31, 2008	3,891	5,424	9,315	816	38,253	16,506
Extensions	211	266	477	17	732	615
Improved recovery	-	-	-	-	-	-
Technical revisions	35	186	221	116	1,825	642
Discoveries	-	-	-	-	-	-
Acquisitions	7	5	12	21	1,068	211
Dispositions	-	-	-	-	-	-
Economic factors	(10)	(7)	(17)	-	93	(2)
Production ⁽³⁾	(537)	(985)	(1,522)	(146)	(6,415)	(2,737)
December 31, 2009	3,596	4,889	8,486	824	35,555	15,236
Proved Plus Probable						
December 31, 2008	5,862	8,584	14,446	1,203	58,348	25,374
Extensions	427	449	876	30	1,193	1,106
Improved recovery	-	-	-	-	-	-
Technical revisions	(180)	113	(67)	101	(322)	(19)
Discoveries	-	-	-	-	-	-
Acquisitions	10	8	18	34	1,640	325
Dispositions	-	-	-	-	-	-
Economic factors	(11)	(10)	(21)	-	171	7
Production ⁽³⁾	(537)	(985)	(1,522)	(146)	(6,415)	(2,737)
December 31, 2009	5,571	8,159	13,730	1,222	54,615	24,054

(1) Numbers may not add due to rounding.

(2) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands.

(3) Production estimated by Trimble.

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

RESERVE LIFE INDEX ⁽¹⁾	Proved	Total	Proved Plus
	Producing	Proved	Probable
Net reserves (Mboe)	15,055	15,236	24,054
Net production (Mboe)	2,254	2,263	2,486
Reserve life index (years)	6.7	6.7	9.7

(1) Calculated by dividing the Trimble forecast of 2010 net production into the remaining net reserves.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

AS AT DECEMBER 31, 2009 - FORECAST PRICES AND COSTS ^{(1) (2)}

(\$000s)	Proved	Proved Plus Probable
Royalty Income	800,067	1,386,532
Revenue from Working Interest Properties	346,386	593,629
Royalty expense on Working Interest Properties	(40,697)	(74,516)
Operating costs	(122,912)	(205,156)
Development costs	(878)	(5,650)
Well abandonment and reclamation costs	(7,356)	(8,710)
Future net revenue before income taxes	974,611	1,686,129
Future income taxes	(172,862)	(351,604)
Future net revenue after income taxes	801,749	1,334,525

(1) Future net revenue values do not represent fair market value.

(2) Future net revenue calculation includes future capital expenditures required to bring booked non-producing and undeveloped reserves on production.

FUTURE DEVELOPMENT COSTS ⁽¹⁾

(\$000s)	Proved Reserves	Proved Plus Probable Reserves
2010	92	2,392
2011	558	2,816
2012	73	73
2013	30	30
2014	30	30
Remainder	95	309
Total	878	5,650

(1) Based on forecast prices and costs. The source of funding for future development costs includes internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures.

NET PRESENT VALUES

OF FUTURE NET REVENUE ^{(1) (2) (3)}

(\$000s)	Before tax, discounted at			
	0% per year	5% per year	10% per year	15% per year
Proved developed producing	966,459	663,285	513,341	424,571
Proved developed non-producing	1,803	1,033	688	506
Proved undeveloped	6,349	4,828	3,831	3,142
Total proved	974,611	669,146	517,860	428,218
Total probable	711,518	316,540	189,723	133,147
Proved plus probable	1,686,129	985,686	707,583	561,366

(1) Columns may not add due to rounding.

(2) Forecast prices and costs, before tax, based on the December 31, 2009 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

(3) Future net revenue values do not represent fair market value.

ANALYSIS OF FINDING, DEVELOPMENT AND ACQUISITIONS (FD&A) COSTS (1) (2) (3) (4)	2009	2008	2007	Three-Year Results
Net Proved Reserves:				
Development expenditures (\$000s)	15,491	12,992	12,167	40,650
Change in future development capital estimates (\$000s)	(295)	597	(2,376)	(2,074)
Net reserve additions by development (Mboe)	615	409	329	1,353
Development costs (\$/boe)	24.70	33.22	29.79	28.51
Acquisition expenditures (\$000s)	9,539	7,693	90,456	107,688
Net reserve additions by acquisition (Mboe)	211	192	1,696	2,100
Acquisition costs (\$/boe)	45.14	40.07	53.33	51.29
Total expenditures (\$000s)	25,030	20,685	102,623	148,338
Change in future development capital estimates (\$000s)	(295)	597	(2,376)	(2,074)
Net reserve additions (Mboe)	827	601	2,025	3,453
Development and acquisition costs (\$/boe)	29.92	35.41	49.50	42.36
Net Proved Plus Probable Reserves:				
Development expenditures (\$000s)	15,491	12,992	12,167	40,650
Change in future development capital estimates (\$000s)	1,944	(564)	(3,305)	(1,925)
Net reserve additions by development (Mboe)	1,106	833	616	2,555
Development costs (\$/boe)	15.77	14.92	14.38	15.16
Acquisition expenditures (\$000s)	9,539	7,693	90,456	107,688
Net reserve additions by acquisition (Mboe)	325	272	2,473	3,070
Acquisition costs (\$/boe)	29.38	28.25	36.57	35.07
Total expenditures (\$000s)	25,030	20,685	102,623	148,338
Change in future development capital estimates (\$000s)	1,944	(564)	(3,305)	(1,925)
Net reserve additions (Mboe)	1,430	1,105	3,090	5,625
Development and acquisition costs (\$/boe)	18.86	18.20	32.15	26.03

- (1) The Trust did not incur any exploration costs in any of the applicable years.
- (2) In calculating finding and development costs, NI 51-101 requires that the exploration and development costs incurred in the year and the change in estimated future development costs be aggregated and then divided by the applicable reserve additions. The calculation specifically excludes the effects of acquisitions on both reserves and costs. We believe that by excluding the effects of acquisitions the provisions of NI 51-101 do not fully reflect the Trust's ongoing reserve replacement costs. Because acquisitions can have a significant impact on the Trust's annual reserve replacement costs, excluding these amounts could result in an inaccurate portrayal of the Trust's cost structure. Accordingly, we also provide costs that incorporate all acquisitions during the year.
- (3) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.
- (4) See "Management's Discussion and Analysis (MD&A) - Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".

RECYCLE STATISTICS

NET PROVED PLUS PROBABLE RESERVES (\$ per boe, except as noted) (1)	2009	2008	2007	Three-Year Results
Operating netback (2) (5)	39.61	65.18	43.54	49.50
Development and acquisition costs (3) (5)	18.86	18.20	32.15	26.03
Recycle ratio (times) (4)	2.1	3.6	1.4	1.9

- (1) See "Management's Discussion and Analysis (MD&A) - Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".
- (2) Total revenue, less operating costs and royalty expenses.
- (3) Development expenditures, plus change in future capital, plus acquisition costs; divided by net reserves added through development and acquisition activities.
- (4) Operating netback divided by the average cost of acquiring and developing new reserves.
- (5) Operating netback is based on gross production, while development and acquisition costs are based on net reserves.

Summary of Land Holdings

SUMMARY OF LAND HOLDINGS (gross acres) (1)	Total Land Holdings		Undeveloped Land	
	2009	2008	2009	2008
Mineral title lands (2)	548,198	549,925	160,232	162,972
Gross overriding royalty (GORR) lands (3)	1,530,160	1,518,423	425,760	423,188
Royalty assumption lands (4)	95,111	95,592	18,925	19,962
Total royalty lands	2,173,469	2,163,940	604,917	606,122
Working interest properties	212,413	210,606	43,445	44,998
Total land holdings	2,385,882	2,374,546	648,362	651,120

LAND HOLDINGS BY PROVINCE (gross acres) (1)	As at December 31		
	2009	2008	2007
Alberta	1,493,335	1,485,388	1,488,098
Saskatchewan	507,707	503,634	505,223
Ontario	295,769	295,769	296,109
British Columbia	80,788	81,472	82,423
Manitoba	8,283	8,283	8,283
Total	2,385,882	2,374,546	2,380,136

- (1) Gross acres represents the total number of acres in which we have an interest.
- (2) The royalties received from the sale of oil, natural gas and potash produced from the leased mineral title lands are determined by the individual lease agreements. Mineral title lands are held in perpetuity. All but 100,546 gross acres of our mineral title lands are currently leased to third parties.
- (3) Gross overriding royalty lands consist of properties owned by a number of third party oil and gas companies in respect of which varying royalties or net profits interests have been reserved to Freehold.
- (4) Mineral title properties owned by a number of third party oil and gas companies in respect of which gross overriding royalties varying from 4.7% to 6.5% have been reserved to Freehold.

Net Asset Value

NET ASSET VALUE AS AT DECEMBER 31, 2009 ^{(1) (2)}

(\$000s, except unit data)	2009	2008	2007
Present value of oil and gas reserves ^{(3) (7)}	707,583	730,659	711,624
Present value of potash reserves ^{(4) (7)}	17,809	27,807	14,317
Undeveloped land ⁽⁵⁾	79,408	93,975	30,252
Reclamation fund ⁽⁶⁾	2,261	1,827	1,788
Working capital ⁽⁶⁾	(3,082)	(20,055)	11,219
Bank debt ⁽⁶⁾	(45,000)	(140,000)	(178,000)
Asset retirement obligations ⁽⁶⁾	(7,160)	(5,663)	(6,608)
Net asset value	751,818	688,550	584,592
Trust Units outstanding (000s)	57,503	49,459	49,317
Net asset value per Trust Unit (\$)	13.06	13.92	11.85

- (1) Non-GAAP measure. Net asset value (NAV) is a measure used widely within the investment community and in the oil and natural gas industry. It shows what is normally referred to as a 'produce-out' NAV calculation under which the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It does not represent a 'going concern' value and it should not be assumed that the present value of oil and gas reserves represent the fair market value of the reserves. Net asset value does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.
- (2) Columns may not add due to rounding.
- (3) Based on net proved plus probable reserves evaluated by Trimble, before tax, discounted at 10%, and includes future capital expenditure expectations required to bring undeveloped reserves on production.
- (4) Based on net proved plus probable reserves evaluated internally, before tax, discounted at 10%. Potash reserves are not subject to NI 51-101.
- (5) Evaluated by Seaton-Jordan & Associates Ltd.
- (6) Financial information per Freehold's consolidated financial statements.
- (7) Future net revenue values do not represent fair market value.

As noted above, subsequent to year-end we acquired additional royalty interests, adding approximately 319,700 gross acres of land, 1.4 MMboe of net proved plus probable reserves, and 435 boe per day of production for 2010. This acquisition is not included in reserves, land and net asset value as at December 31, 2009.

Management's Discussion and Analysis (MD&A)

The following discussion is management's opinion about the operating and financial results of Freehold Royalty Trust, Freehold Resources Ltd. and Petrovera Resources (a general partnership) (collectively, Freehold or the Trust), for the three and twelve months ended December 31, 2009 and previous periods, and the outlook for Freehold based on information available as at March 3, 2010. The financial information contained herein was based on information in the consolidated financial statements, which have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended December 31, 2009 and December 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 March 3, 2010, and contains forward-looking statements including our expectations for improving economic conditions, industry drilling and activity on our royalty lands and the benefits therefrom, capital expenditures, average production, commodity prices including our outlook for crude oil and natural gas, demand for heavier crude, and acquisition opportunities referred to in the Message to Unitholders; Future Income Tax; and our expectations for improving economic conditions, access to capital markets, industry drilling and activity on our royalty lands, participation in the DRIP, long-term debt, capital expenditures, average production, commodity prices including our outlook for crude oil and natural gas, demand for and differential pricing of heavier crude, key operating assumptions, and acquisition opportunities referred to under Business Environment. These forward-looking statements are provided to allow readers to better understand our business and prospects.

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

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, future oil and natural gas prices, future capital expenditure levels, future production levels, future exchange rates, future participation rates in the DRIP, the cost of developing and producing our assets, our ability and the ability of our lessees to obtain equipment in a timely manner to carry out development activities, our ability to market our oil and natural gas successfully to current and new customers, our expectation for the consumption of crude oil and natural gas, our expectation for industry drilling levels, our ability to obtain financing on acceptable terms, and our ability to add production and reserves through development and acquisition activities. The key operating assumptions with respect to the forward-looking statements referred to above are detailed in our discussion of the Business Environment.

You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in the MD&A is expressly qualified by this cautionary statement. Our policy for updating forward-looking

statements is to update our key operating assumptions quarterly and, except as required by law, we do not undertake to update any other forward-looking statements.

CONVERSION OF NATURAL GAS TO BARRELS OF OIL EQUIVALENT (BOE)

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation.

NON-GAAP MEASURES

Within this MD&A, references are made to terms commonly used as key performance indicators in the oil and gas industry. We believe that operating netback, funds generated from operations, and net debt to funds generated from operations are useful supplemental measures for management and investors to analyze operating performance, financial leverage, and liquidity, and we use these terms to facilitate the understanding and comparability of our results of operations and financial position. However, these terms do not have any standardized meanings prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.

Operating netback, which is calculated as average unit sales price less royalties and operating expenses, represents the cash margin for product sold, calculated on a per boe basis. See Operating Netback.

Funds generated from operations is a financial term commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital and is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with GAAP. The key difference between cash provided by operating activities and funds generated from operations is changes in non-cash working capital, which is affected by accounts receivable, accounts payable, and accrued liabilities. Accounts receivable, and therefore working capital, can fluctuate greatly between reporting periods due to timing of receipt of payments. In the event that commodity prices and/or volumes have changed significantly from the previous reporting period, a significant difference could occur between cash provided by operating activities and funds generated from operations. All references to funds generated from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital as per the Statements of Cash Flows. Funds generated from operations per Trust Unit is calculated based on the weighted average number of Trust Units outstanding consistent with the calculation of net income per Trust Unit. See Funds Generated From Operations and Net Income.

Net debt to funds generated from operations is calculated as net debt (total debt less positive working capital) as a proportion of funds generated from operations for the previous twelve months. See Debt Analysis.

In addition, we refer to various per boe figures, such as revenues and costs, also considered non-GAAP measures, which provide meaningful information on our operational performance. We derive per boe figures by dividing the relevant revenue or cost figure by the total volume of oil and natural gas production during the period, with natural gas converted to equivalent barrels of oil as described above.

Business Environment

An improving global economic outlook has contributed to a gradual oil price improvement over the past several months, although the benefit has been partly offset by a corresponding rise of the Canadian dollar. Markets for heavy oil remain robust due to strong refinery demand for this product type. Winter weather has increased heating demand throughout North America, and natural gas markets have responded with modest price increases. While these factors are positive in the short-term, we believe that the road to full economic recovery will be long and bumpy. Overall, the outlook for crude oil is more favourable than for natural gas and, with our oil-weighted production, Freehold is well positioned to continue to benefit from strengthening oil markets.

Industry activity levels in the final three months of the year remained muted compared to 2008 with fewer than 500 wells drilled in western Canada. Industry drilled 55% fewer wells overall in 2009 than in 2008, and the average utilization rate for Canadian drilling rigs was at an all time low of 26%.

The Petroleum Services Association of Canada recently updated its 2010 Canadian drilling activity forecast and is “cautiously optimistic” that commodity prices will strengthen further in 2010, leading to increased drilling activity. The Alberta Government’s short-term stimulus plan to encourage conventional oil and natural gas activity in the province is also expected to have a positive impact on industry activity levels in the coming months. While operators may focus on opportunities on Crown lands to take advantage of the incentives, we anticipate that increased activity will be eventually reflected on our royalty lands.

DEVELOPMENT ON OUR ROYALTY LANDS

We have royalty interests in 2.2 million gross acres of land throughout the Western Canada Sedimentary Basin and receive royalties from approximately 250 industry operators. This diversity lowers our risk, while we benefit from the drilling activity of others. As a royalty interest owner, we do not pay any of the capital costs to drill and equip the wells for production, nor do we incur costs to operate the wells, maintain production, and ultimately restore the land to its original state. All of the costs are paid by others and we simply receive a royalty on the gross production revenue.

As expected, drilling on our royalty lands in 2009 reflected the overall decline in industry activity levels; however, as at December 31, 2009, there were 86 licensed drilling locations on our royalty lands, up from 64 locations a year ago.

DRILLING ON ROYALTY LANDS	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
Unitized wells						
Gross	27	24	13%	316	252	25%
Equivalent net (1)	0.0	0.0	-	1.1	1.0	10%
Non-unitized wells						
Gross	65	80	-19%	162	353	-54%
Equivalent net (1)	3.4	4.0	-15%	7.5	15.4	-51%
Total						
Gross	92	104	-12%	478	605	-21%
Equivalent net (1)	3.4	4.0	-15%	8.6	16.4	-48%

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

ROYALTY ACQUISITIONS

As announced in a news release on February 18, 2010, we recently completed two royalty acquisitions for \$49 million. Both acquisitions were financed through our existing credit facilities and are accretive, on a debt-adjusted per unit basis, to cash flow, production, reserves, and net asset value. These acquisitions support our strategy of focusing on oil and gas royalties. The creation of overriding royalties provides benefits to both parties. For the vendors, the sale proceeds provide a source of capital to fund their ongoing development activities. For Freehold, the acquired royalty

interests bring strong netbacks, as production is unencumbered by operating and capital costs and third party royalty expenses. The acquisitions also allow us to benefit from future development on the properties.

WORKING INTEREST PROPERTIES

In the fourth quarter of 2009, we participated in the drilling of three (1.2 net) Bakken wells. One (0.5 net) well was a stratigraphic test and considered dry and abandoned; the other two (0.7 net) wells came on production in December. Since 2005, we have participated in the drilling of 28 (7.7 net) Bakken wells on our lands.

Our first two 100% wells on our Bakken oil-prone lands in Southeast Saskatchewan, drilled in the third quarter of 2009, commenced production in November, and each averaged 80 barrels per day in December.

DRILLING ON WORKING INTEREST PROPERTIES	Three Months Ended December 31				Twelve Months Ended December 31			
	2009		2008		2009		2008	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	2	0.7	2	1.0	25	7.6	31	6.9
Natural gas	-	-	-	-	1	-	9	0.7
Other	1	0.5	1	0.1	2	0.6	2	0.1
Total	3	1.2	3	1.1	28	8.2	42	7.7

DISTRIBUTION POLICY

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

The following table summarizes our key operating assumptions for 2009. Operating costs per boe were about 7% higher than expected, as a result of a one-time adjustment of approximately \$800,000 (\$0.30 per boe) for expenses incurred from 2005 to 2008. Capital expenditures were \$1.5 million higher than previously anticipated; the majority of the increase related to the drilling of an additional partner-operated Bakken well at Taylorton, Saskatchewan. Long-term debt was significantly lower than our earlier guidance, as the proceeds from our equity offering in December were initially applied to debt repayment.

2009 KEY OPERATING ASSUMPTIONS	2009					News
	Actual	MD&A	MD&A	MD&A	MD&A	Release
	Results	Dated	Dated	Dated	Dated	Dated
	Mar. 3	Nov. 10	Aug. 12	May 13	Mar. 11	Jan. 20
	2010	2009	2009	2009	2009	2009
Average daily production (boe/d)	7,302	7,300	7,300	7,500	7,500	7,500
Average WTI oil price (US\$/bbl)	61.81	60.00	60.00	44.00	44.00	50.00
Average AECO natural gas price (Cdn\$/Mcf)	4.13	3.70	3.70	5.00	5.00	7.00
Average exchange rate (Cdn\$/US\$)	0.88	0.88	0.87	0.80	0.80	0.80
Average operating costs (\$/boe)	4.37	4.10	4.10	4.10	4.10	4.10
Average G&A costs (\$/boe) (1)	2.71	2.90	2.90	2.90	2.90	2.90
Capital expenditures (\$ millions)	15.5	14.0	12.0	12.0	12.0	12.0
Long-term debt at year end (\$ millions)	45.0	146.0	155.0	159.0	159.0	159.0
Weighted average Trust Units outstanding (thousands)	50,000	48,563	49,521	49,514	49,514	49,514
Estimated portion of distributions taxable as income (%)	82%	90-100%	90-100%	90-100%	90-100%	90-100%

(1) Excludes unit based and other compensation.

2010 PLANS

On our working interest properties, we anticipate spending approximately \$24 million in 2010. This represents a substantial increase over 2009, as we plan to accelerate development of our Bakken-prone title lands in Southeast Saskatchewan. In addition, we anticipate an active program at Pembina Cardium Unit #9 as the operator, Penn West, continues with field redevelopment using horizontal infill drilling and multi-stage fracture stimulation. With additional production from our recent acquisitions and a larger capital program, we are forecasting average production of 7,600 boe per day for 2010; royalty interests are expected to account for 70% of this production. General and administrative costs will be higher than last year as a result of consulting fees related to our IFRS conversion project and evaluation of the impact of the SIFT tax. DRIP proceeds of approximately \$24 million will be used to reduce debt and fund a portion of our capital program. As we are now issuing DRIP units from treasury, the weighted average number of Trust Units outstanding is expected to be 58.4 million.

2010 KEY OPERATING ASSUMPTIONS

	March 3 2010	Nov. 10 2009
Average daily production (boe/d)	7,600	7,000
Average WTI oil price (US\$/bbl)	80.00	75.00
Average AECO natural gas price (Cdn\$/Mcf)	5.00	5.00
Average exchange rate (Cdn\$/US\$)	0.96	0.90
Average operating costs (\$/boe)	4.30	4.75
Average G&A costs (\$/boe) (1)	3.20	3.00
Capital expenditures (\$ millions)	24.0	24.0
Proceeds from DRIP (\$ millions) (2)	24.0	-
Long-term debt at year end (\$ millions)	53.7	125.0
Weighted average Trust Units outstanding (thousands)	58,363	50,734
Estimated portion of distributions taxable as income (%)	90-100%	90-100%

(1) Excludes unit based and other compensation.

(2) Assumes a 24% participation rate in 2010.

Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including light/heavy oil price differentials), foreign exchange rates, or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as roughly one third of our total boe production is heavy oil.

A sensitivity analysis of the potential impact of key variables on distributions to Unitholders is provided below.

SENSITIVITY ANALYSIS

Variables	Change (+/-)	Estimated Change in Distributions to Unitholders	
		(\$000s)	(\$/Trust Unit)
WTI crude oil price	US\$1.00/bbl	1,860	0.03
Light/heavy oil price differential	Cdn\$1.00/bbl	1,753	0.03
Natural gas price	Cdn\$0.25/Mcf	1,530	0.03
Exchange rate (US\$/Cdn\$)	0.01	1,408	0.02
Interest rates	1%	500	0.01
Oil and NGL production	100 bbls/d	2,605	0.04
Natural gas production	1,000 Mcf/d	1,765	0.03

Results of Operations

Overall, our results for the fourth quarter reflect improved oil prices compared with the fourth quarter of 2008, while results for the twelve months ended December 31, 2009 reflect lower production and lower selling prices due to the steep decline in commodity prices compared with last year.

FUNDS GENERATED FROM OPERATIONS AND NET INCOME (\$000s, except as noted)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
Cash provided by operating activities	25,937	41,672	-38%	95,659	179,252	-47%
Changes in non-cash working capital	4,507	(14,730)	131%	(574)	(7,970)	93%
Funds generated from operations	30,444	26,942	13%	95,085	171,282	-44%
Per Trust Unit (\$)	0.59	0.55	7%	1.90	3.47	-45%
Net income	14,721	13,374	10%	31,741	109,956	-71%
Per Trust Unit, basic and diluted (\$)	0.29	0.27	6%	0.63	2.23	-72%

PRODUCTION

On a boe basis, our production was down 5% in the fourth quarter and down 6% for the year, as drilling activity and acquisitions during 2009 were insufficient to offset natural production declines on our royalty lands. The deferral of our major capital projects to the second half of the year also contributed to the decline in working interest production.

Royalty interests contributed 69% (2008 Q4 – 70%) of total volumes produced in the quarter. Our production mix for the year was approximately 36% natural gas and 64% liquids (33% heavy oil, 27% light and medium oil, and 4% NGL).

AVERAGE DAILY PRODUCTION	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
Royalty lands						
Oil (bbls/d)	2,995	2,894	3%	2,842	2,922	-3%
NGL (bbls/d)	199	296	-33%	249	259	-4%
Natural gas (Mcf/d)	11,555	13,800	-16%	12,336	14,196	-13%
Oil equivalent (boe/d)	5,120	5,490	-7%	5,147	5,546	-7%
Working interest properties						
Oil (bbls/d)	1,656	1,671	-1%	1,534	1,646	-7%
NGL (bbls/d)	81	92	-12%	74	78	-5%
Natural gas (Mcf/d)	3,272	3,157	4%	3,279	3,203	2%
Oil equivalent (boe/d)	2,282	2,289	0%	2,155	2,258	-5%
Total Trust						
Oil (bbls/d)	4,651	4,565	2%	4,376	4,568	-4%
NGL (bbls/d)	280	388	-28%	323	337	-4%
Natural gas (Mcf/d)	14,827	16,957	-13%	15,615	17,399	-10%
Oil equivalent (boe/d)	7,402	7,779	-5%	7,302	7,804	-6%
Number of days in period (days)	92	92	0%	365	366	0%
Total volumes during period (Mboe)	681	716	-5%	2,665	2,856	-7%

MARKETING AND HEDGING

As at December 31, 2009, we marketed approximately 42% of our royalty oil production and most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. Approximately 20% of our working interest natural gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed referenced prices. The balance of our working interest natural gas production (80%) is marketed with the operators' production.

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

COMMODITY PRICES

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

AVERAGE BENCHMARK PRICES (1)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
WTI crude oil (US\$/bbl)	76.19	58.69	30%	61.81	99.64	-38%
US\$/Cdn\$ exchange rate	0.9467	0.8250	15%	0.8798	0.9428	-7%
Edmonton Par crude oil (Cdn\$/bbl)	76.56	63.21	21%	65.90	102.16	-35%
Western Canada Select/Hardisty (Cdn\$/bbl)	67.65	47.72	42%	58.66	82.90	-29%
Light/heavy oil differential (Cdn\$/bbl)	8.91	15.49	-42%	7.24	19.26	-62%
AECO natural gas (Cdn\$/Mcf)	4.23	6.78	-38%	4.13	8.13	-49%

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

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

AVERAGE SELLING PRICES	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
Oil (\$/bbl)	66.94	49.82	34%	57.24	83.45	-31%
NGL (\$/bbl)	50.39	48.28	4%	41.93	67.60	-38%
Oil and NGL (\$/bbl)	66.00	49.70	33%	56.19	82.36	-32%
Natural gas (\$/Mcf)	3.56	6.84	-48%	3.67	8.15	-55%
Oil equivalent (\$/boe)	51.09	46.55	10%	44.00	69.93	-37%

QUARTERLY PERFORMANCE AND TRENDS

Our performance is directly influenced by commodity prices, which are determined by supply and demand factors, weather, seasonality, global political events, general economic conditions, and changes in Canadian/U.S. dollar exchange rates. Quarterly variances in revenues, net income, cash provided by operating activities, and funds generated from operations are caused mainly by fluctuations in commodity prices and production volumes. Crude oil prices are generally determined by global supply and demand factors, but the variances do not have 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.

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

- WTI crude oil prices exhibited significant volatility. After reaching record levels in mid-2008, the benchmark price fell significantly in the last half of 2008 as global economic conditions deteriorated. Low prices prevailed through the first quarter of 2009 and then improved through the remainder of 2009.
- Fluctuations in U.S. to Canadian dollar exchange rates also affected our oil price realizations, resulting in both positive and negative effects on our Canadian dollar oil revenues relative to the benchmark WTI, which is referenced in U.S. dollars.
- Heavy oil differentials narrowed significantly from historical levels. U.S. demand for Canadian heavy crude has risen as imports from Mexico and Venezuela have declined. Domestic demand for heavy oil is typically highest during the summer paving season.
- AECO natural gas prices also exhibited significant volatility. Natural gas markets strengthened briefly in mid-2008; however, with supply continuing to outstrip demand, prices continued to face downward pressure, falling to a 10-year low during the third quarter of 2009. Natural gas is a typically seasonal, weather-dependent fuel; demand is generally higher during the winter (for heating) and summer (for cooling), and lower during the spring and fall.
- We adjusted our monthly distributions in response to changing commodity prices. In April 2008, we raised the rate by \$0.03 to \$0.18 per Trust Unit, and raised it again in June 2008, to \$0.25 per Trust Unit. We also declared an additional distribution of \$0.35 per Trust Unit for 2008, which was paid to Unitholders on January 15, 2009. The distributions payable to Unitholders (current liability) at year-end 2008 was higher than at year-end 2009 because the additional distribution for 2008 was not paid until 2009. In January 2009, we lowered the rate to \$0.10 per Trust Unit. As oil prices strengthened, we increased the rate to \$0.12 per Trust Unit in August 2009, and increased it again in November 2009, to \$0.14 per Trust Unit. We also declared an additional distribution of \$0.06 per Trust Unit for 2009, which was paid in the fourth quarter.
- In 2007 and 2008, the oil and gas industry experienced rising costs due to strong economic growth. These inflationary pressures began to ease in late 2008 as weak commodity prices cooled industry activity levels and brought down power costs.
- Fluctuations in our Trust Unit price resulted in corresponding changes in unit based compensation, which is based in part on the closing unit price at each quarter end.
- Under Freehold's Distribution Reinvestment Plan (DRIP), commencing with the October distribution (payable on November 15, 2009), we began issuing DRIP Trust Units from treasury instead of purchasing them in the market. Also with the November 15, 2009 distribution payment, CN Pension Trust Funds, which owns approximately 23% of Freehold's Trust Units, began to participate in the DRIP. This gives us a new source of capital to reinvest in the development of our working interest properties, reduce long-term debt, or fund acquisitions. DRIP proceeds for the final two months of 2009 were \$3.9 million.
- On December 10, 2009, Freehold closed an equity offering and issued 7.6 million Trust Units. Net proceeds of \$110.5 million were used to reduce long-term debt.
- On December 21, 2009, We closed a \$10 million royalty acquisition. The acquisition was funded through our existing credit facilities.

QUARTERLY REVIEW	2009				2008			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial (\$000s, except as noted)								
Revenue, net of royalty expense	33,966	29,435	28,516	25,315	33,174	58,210	59,563	46,553
Distributions declared	23,937	16,850	14,852	14,841	54,387	37,050	30,114	22,198
Per Trust Unit (\$) (1) (2)	0.46	0.34	0.30	0.30	1.10	0.75	0.61	0.45
Net income	14,721	7,853	6,776	2,391	13,374	36,772	36,163	23,647
Per Trust Unit, basic and diluted (\$)	0.29	0.16	0.14	0.05	0.27	0.74	0.73	0.48
Cash provided by operating activities	25,937	26,215	21,938	21,569	41,672	57,380	46,379	33,821
Per Trust Unit (\$)	0.50	0.53	0.44	0.44	0.84	1.16	0.94	0.69
Funds generated from operations (3)	30,444	24,189	21,833	18,619	26,942	51,977	53,183	39,182
Per Trust Unit (\$)	0.59	0.49	0.44	0.38	0.55	1.05	1.08	0.79
Property and royalty acquisitions	9,539	-	-	-	(782)	8,475	-	-
Capital expenditures	4,435	7,368	1,661	2,027	3,770	9,222	2,135	2,202
Long-term debt	45,000	147,000	156,000	160,000	140,000	141,000	151,000	169,000
Trust Units outstanding								
Weighted average (000s)	51,483	49,543	49,495	49,460	49,424	49,389	49,353	49,317
At quarter end (000s)	57,503	49,582	49,531	49,495	49,459	49,424	49,388	49,352
Operating (\$/boe, except as noted)								
Daily production (boe/d)	7,402	6,994	7,295	7,522	7,779	7,613	7,674	8,152
Royalty interest production (%)	69	71	71	70	71	71	72	71
Average selling price	51.09	44.01	42.99	37.85	46.55	83.47	86.43	64.16
Operating netback (3)	45.66	42.16	37.56	33.13	42.14	79.14	81.21	59.18
Operating expenses	4.22	3.59	5.39	4.27	4.21	3.97	4.08	3.58
Working interest properties	13.69	12.59	18.78	14.27	14.31	13.51	14.37	12.54
General and administrative expenses	2.38	2.35	2.12	3.98	2.20	1.95	2.15	3.16
Benchmark Prices								
WTI crude oil (US\$/bbl)	76.19	68.30	59.62	43.08	58.69	117.98	123.98	97.86
Exchange rate (Cdn\$/US\$)	0.95	0.91	0.86	0.80	0.83	0.96	0.99	1.00
Edmonton Par crude oil (Cdn\$)	76.56	71.50	65.90	49.66	63.21	121.85	126.07	97.50
Western Canada Select/Hardisty (Cdn\$/bbl)	67.65	63.75	60.71	42.54	47.72	103.87	103.32	76.70
Light/heavy oil differential (Cdn\$/bbl) (4)	8.91	7.75	5.19	7.12	15.49	17.98	22.75	20.80
AECO natural gas (Cdn\$/Mcf)	4.23	3.02	3.66	5.62	6.78	9.24	9.35	7.13
Unit Trading Performance								
High (\$)	16.28	17.00	15.18	11.76	18.43	24.35	24.40	19.29
Low (\$)	14.02	12.75	8.70	6.87	9.15	16.01	17.51	14.55
Close (\$)	15.09	16.24	13.85	8.90	10.49	17.10	23.99	18.04
Volume (000s)	6,827	5,131	8,756	9,310	10,474	10,263	8,993	6,740

- (1) Based on the number of Trust Units issued and outstanding at each record date.
- (2) The fourth quarters include additional distributions relating to excess income earned during the full year (\$0.06 per Trust Unit in 2009 and \$0.35 per Trust Unit in 2008).
- (3) See Non-GAAP Measures.
- (4) The difference between Edmonton Par and Western Canada Select/Hardisty crude oil streams.

Revenue and Other Income

Gross revenue in the fourth quarter of 2009 was slightly higher than last year due to the relative strength of oil prices compared with the fourth quarter of 2008. For the twelve months ended December 31, 2009, gross revenue was significantly lower than the previous year, due to lower realized prices and, to a lesser extent, lower production volumes. Other income relates to a \$2.1 million judgment awarded to Freehold in the fourth quarter of 2009 arising from a statement of claim for incorrect royalty payments and production from a terminated lease (see note 8).

REVENUE AND OTHER INCOME (\$000s)	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	Change	2009	2008	Change
Gross revenue	35,167	34,461	2%	119,965	204,116	-41%
Royalty and mineral tax expense (1)	(1,201)	(1,287)	-7%	(2,733)	(6,616)	-59%
Net revenue	33,966	33,174	2%	117,232	197,500	-41%
Other income	2,122	-	100%	2,122	-	100%

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

The accompanying table demonstrates the net effect of price and volume variances on gross revenues.

GROSS REVENUE VARIANCES (\$000s)	Three Months Ended December 31		Twelve Months Ended December 31	
	2009 vs. 2008	2008 vs. 2007	2009 vs. 2008	2008 vs. 2007
Oil and NGL				
Production decrease	(134)	(2,482)	(4,477)	(13,510)
Price increase (decrease)	7,430	(4,477)	(46,976)	55,199
Net increase (decrease)	7,296	(6,959)	(51,453)	41,689
Natural gas				
Production decrease	(697)	(1,016)	(2,450)	(3,738)
Price increase (decrease)	(5,117)	1,316	(28,559)	11,473
Net increase (decrease)	(5,814)	300	(31,009)	7,735
Other (1)	(776)	609	(1,689)	2,508
Gross revenue increase (decrease)	706	(6,050)	(84,151)	51,932

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

Expenses

ROYALTY EXPENSE AND MINERAL TAX

We do not incur royalty expense on production from our royalty lands. As the royalty owner, we receive the royalty as income from other companies. Mineral tax is payable annually to the Crown, in the first quarter of the year. Crown royalty rates, which are tied to commodity prices and production volumes, were significantly lower in 2009, due to lower commodity prices and, to a lesser extent, lower production compared with last year. Mineral tax on our royalty lands for the twelve months ended December 31, 2009 includes \$1.3 million of freehold mineral tax recovered from certain lessees.

ROYALTY EXPENSE AND MINERAL TAX (1) (\$000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	Change	2009	2008	Change
Working interest properties						
Crown royalties	682	945	-28%	2,018	4,488	-55%
Third party royalties	346	235	47%	875	1,145	-24%
Mineral tax	119	106	12%	489	445	10%
Working interest properties	1,147	1,286	-11%	3,382	6,078	-44%
Per boe (\$)	5.46	6.11	-11%	4.30	7.36	-42%
Royalty lands						
Crown royalties	-	-	-	-	-	-
Third party royalties	-	-	-	-	-	-
Mineral tax	54	1	-	(649)	538	-221%
Royalty lands	54	1	-	(649)	538	-221%
Per boe (\$)	0.11	-	-	(0.35)	0.27	-230%
Total Trust	1,201	1,287	-7%	2,733	6,616	-59%
Per boe (\$)	1.76	1.80	-2%	1.03	2.32	-56%

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

OPERATING EXPENSES

Operating expenses in the fourth quarter were 5% lower than last year. Included in operating expenses for the twelve months ended December 31, 2009 was a one-time adjustment of approximately \$800,000 (\$1.01 per boe) for expenses incurred on certain working interest properties from 2005 to 2008 (\$0.30 per boe on a total Trust basis).

OPERATING EXPENSES (\$000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	Change	2009	2008	Change
Working interest properties	2,876	3,015	-5%	11,655	11,299	3%
Per boe (\$)	13.69	14.31	-4%	14.82	13.67	8%
Royalty lands (1)	-	-	-	-	-	-
Per boe (\$)	-	-	-	-	-	-
Total operating expenses	2,876	3,015	-5%	11,655	11,299	3%
Total Trust (\$/boe)	4.22	4.21	0%	4.37	3.96	10%

(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 extend from northeastern British Columbia to southern Ontario. As a royalty owner, we share in production revenue without incurring the operational costs, risks, and responsibilities typically associated with oil and gas operations. The following table demonstrates the advantage of our royalty lands which yield higher operating netbacks than our working interest properties. Royalty interests contributed approximately 70% of total volumes produced in 2009.

NETBACK ANALYSIS (\$000s)	Twelve months ended December 31, 2009		
	Royalty Interest	Working Interest	Total Trust
	Lands	Properties	
Gross revenue (1)	81,231	38,734	119,965
Royalty expense and mineral tax (2)	649	(3,382)	(2,733)
Net revenue	81,880	35,352	117,232
Operating expense	-	(11,655)	(11,655)
Operating netback	81,880	23,697	105,577

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

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

Our operating netback per boe for the twelve months ended December 31, 2009 declined significantly due to lower commodity prices. Our netback improved in the fourth quarter of 2009 due to higher oil prices.

OPERATING NETBACK (\$/boe)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
Gross revenue (1)	51.64	48.15	7%	45.01	71.46	-37%
Royalty expense and mineral tax (2)	(1.76)	(1.80)	-2%	(1.03)	(2.32)	-56%
Operating expenses	(4.22)	(4.21)	0%	(4.37)	(3.96)	10%
Operating netback	45.66	42.14	8%	39.61	65.18	-39%

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

(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 G&A expenses incurred by the Manager on behalf of the Trust (see Related Party Transactions). We have significant land administration, accounting and auditing requirements to administer and collect royalty payments, including systems to track development activity on the royalty lands. In 2009, we incurred higher office rent, directors' fees, salaries, and software fees, as well as expenses related to our IFRS conversion project.

G&A EXPENSES (\$000s, except as noted)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
G&A expenses	1,622	1,574	3%	7,234	6,790	7%
Per boe (\$)	2.38	2.20	8%	2.71	2.38	14%
As a percentage of revenue	5%	5%	0%	6%	3%	100%

UNIT BASED AND OTHER COMPENSATION

Manager's Long-Term Incentive Plan (LTIP)

After a three-year vesting period, employees of the Manager receive cash compensation in relation to the value of a specified number of notional units. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. The LTIP liability is estimated at the end of each quarter based on the quarter-end Trust Unit price and performance factors; the related compensation charges are recognized over the vesting period. The 2006 LTIP grants vested in January 2009 and \$81,000 of unit based compensation was paid out in the first quarter of 2009. A current liability of \$1.5 million at December 31, 2009 relates to 2007 LTIP grants, which vested and were paid out in February 2010.

Deferred Trust Unit Plan

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

In the fourth quarter, 331 deferred trust units were granted to Rodger Tourigny, who was appointed to the Board on November 10, 2009. William Siebens redeemed 22,038 deferred trust units following his retirement from the Board in 2009 and was issued 15,427 Trust Units from treasury.

Retirement Benefit Plan

In 2009, the Trust agreed to participate in its proportionate share of a retirement benefit for certain employees of the Manager. The retirement benefit is payable in four equal instalments upon retirement after reaching the age of 65. Service costs are amortized on a straight-line basis over the expected average remaining service lifetime.

UNIT BASED AND OTHER COMPENSATION (\$000s, except as noted)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
Manager's long-term incentive plan	344	(893)	139%	2,862	(203)	1510%
Deferred trust unit plan	28	32	-13%	352	300	17%
Retirement benefit	504	-	-	504	-	-
Unit based and other compensation	876	(861)	202%	3,718	97	3733%
Per boe (\$)	1.29	(1.20)	208%	1.40	0.03	4567%
As a percentage of revenue	2%	-2%	200%	3%	0%	100%

INTEREST AND FINANCING

Interest and financing expense declined 25% in the fourth quarter of 2009 due to a reduction in lending rates and significantly lower debt levels compared with last year. Interest and financing expense for the twelve months ended December 31, 2009 included rollover fees related to the annual renewal of our credit facilities in May of 2009. The average effective interest rate on advances under our credit facilities in 2009 was 2.4% (2008 – 4.3%).

INTEREST AND FINANCING (\$000s, except as noted)	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
Interest and financing expense	1,049	1,391	-25%	4,678	7,039	-34%
Per boe (\$)	1.54	1.94	-21%	1.76	2.46	-28%

DEPLETION AND DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION

Oil and gas properties and royalty interests, including the cost of production equipment, future capital costs associated with proved reserves, and the capitalized portion of asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties payable (see Critical Accounting Estimates). Reserves are independently evaluated every year as at December 31. For the first three quarters of 2009, the estimate of proved reserves was based on the independent evaluation dated December 31, 2008, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2009.

Our ceiling test calculation, performed at December 31, 2009, resulted in no impairment loss. The future prices used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for our product quality, transportation, and contract differences.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSES (\$000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	Change	2009	2008	Change
	Depletion and depreciation	15,780	16,076	-2%	63,060	67,948
Accretion of asset retirement obligation	87	96	-9%	333	384	-13%
Total depletion, depreciation and accretion expenses	15,867	16,172	-2%	63,393	68,332	-7%
Per boe (\$)	23.30	22.60	3%	23.79	23.92	-1%

MANAGEMENT FEES

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

MANAGEMENT FEES (Paid in Trust Units)	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	Change	2009	2008	Change
	Trust Units issued in payment of management fees	41,635	35,654	17%	148,597	142,616
Ascribed value (\$000s) (1)	628	374	68%	2,018	2,482	-19%
Per boe (\$)	0.92	0.52	77%	0.76	0.87	-13%

(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

As a result of changes to the SIFT tax rules enacted in the first quarter of 2009, the provincial component of the SIFT tax applicable to Freehold was reduced from 13% to 10%. This will result in a combined SIFT tax rate of 26.5% in 2011, and 25.0% thereafter. In the fourth quarter of 2009, we recorded a \$1.5 million recovery in future income tax, bringing the total recovery for the twelve months ended December 31, 2009 to \$5.3 million.

Liquidity and Capital Resources

CAPITAL EXPENDITURES

We have no capital requirements with respect to our royalty properties. Our capital expenditure obligations (with respect to our working interest properties) are deducted from funds generated from operations prior to determining distributions to Unitholders. Expenditures in the fourth quarter included \$10.0 million on acquisitions and \$4.4 million on development of our working interest properties. We also recovered \$0.5 million related to adjustments of prior year acquisitions. In 2008, we acquired certain royalty and minor working interests in Alberta for \$8.5 million, and recovered \$0.8 million related to adjustments of prior acquisitions.

ACQUISITIONS AND CAPITAL EXPENDITURES (\$000s, except as noted)	Three Months Ended December 31			Twelve Months Ended December 31		
	2009	2008	Change	2009	2008	Change
	Property and royalty acquisitions (net)	9,539	(782)	1320%	9,539	7,693
Capital expenditures	4,435	3,770	18%	15,491	12,992	19%
Change in reclamation fund	104	71	46%	434	39	1013%
	14,078	3,059	360%	25,464	20,724	23%

WORKING CAPITAL

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

At the end of 2009, we had a working capital deficiency of \$3.1 million, and higher accounts receivable attributable to higher oil prices and other income. At year-end 2008, current liabilities included the December distribution of \$0.60 per Trust Unit (of which \$0.35 related to additional income earned in 2008) that was paid on January 15, 2009.

COMPONENTS OF WORKING CAPITAL (\$000s)	Dec. 31 2009	Sept. 30 2009	June 30 2009	Mar. 31 2009	Dec. 31 2008
Cash	432	311	369	546	537
Current portion of deferred compensation	-	-	-	34	-
Accounts receivable	24,056	19,622	21,315	21,870	23,261
Current assets	24,488	19,933	21,684	22,450	23,798
Distributions payable to Unitholders	(8,050)	(5,950)	(4,953)	(4,950)	(29,676)
Current portion of unit based compensation	(1,643)	(1,559)	(743)	(131)	(83)
Accounts payable and accrued liabilities	(17,877)	(20,243)	(13,824)	(15,780)	(14,094)
Current liabilities	(27,570)	(27,752)	(19,520)	(20,861)	(43,853)
Working capital (1)	(3,082)	(7,819)	2,164	1,589	(20,055)

(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 ranging from 150 to 300 basis points, 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 December 31, 2009, we had \$165 million of available capacity under our credit facilities. Net proceeds from our equity issue in December were used, initially, to reduce long-term debt. On December 21, 2009, we drew on our credit facilities to fund a \$10 million royalty acquisition. Subsequent to year-end, we drew on our credit facilities to fund a \$39 million acquisition. By comparison, at December 31, 2008, we had \$70 million of available capacity under our credit facilities, but some of this capacity was used to pay December's distribution paid on January 15, 2009. The effect of December's distribution payable was shown in a working capital deficiency of \$20.1 million and net debt of \$160.1 million at December 31, 2008.

Our borrowing base is dependent on our lenders' annual review and interpretation of our reserves and future commodity prices. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice. Our next review process is expected to be completed in May 2010.

DEBT ANALYSIS (\$000s)	As at December 31		
	2009	2008	Change
Long-term debt	45,000	140,000	-68%
Short-term debt	-	-	-
Total debt	45,000	140,000	-68%
Working capital deficiency	3,082	20,055	-85%
Net debt obligations	48,082	160,055	-70%

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 December 31, 2009, the Trust was in compliance with all such covenants.

FINANCIAL LEVERAGE AND COVERAGE RATIOS (1)	As at December 31		
	2009	2008	Change
Net debt to funds generated from operations (times)	0.5	0.9	-44%
Net debt to distributions (times)	0.7	1.1	-36%
Distributions to interest expense (times)	15.1	20.4	-26%
Net debt to net debt plus equity (%)	14%	42%	-67%

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

DISTRIBUTIONS

Distributions in the fourth quarter totalled \$23.9 million (\$0.46 per Trust Unit), including an additional distribution of \$0.06 per Trust Unit for 2009 (paid on December 15) as a result of excess cash from operating activities, which was distributed to Unitholders in order to eliminate direct taxation at the Trust Level. Cumulative distributions (from 1996 to December 31, 2009) totalled \$794.9 million (\$20.53 per Trust Unit).

ACCUMULATED DISTRIBUTIONS	Three Months Ended December 31		Twelve Months Ended December 31	
	2009	2008	2009	2008
Distributions declared (\$000s)	23,937	54,387	70,480	143,749
Accumulated, beginning of period	770,961	670,031	724,418	580,669
Accumulated, end of period	794,898	724,418	794,898	724,418
Distributions per Trust Unit (\$) (1)	0.46	1.10	1.40	2.91
Accumulated, beginning of period	20.07	18.03	19.13	16.22
Accumulated, end of period	20.53	19.13	20.53	19.13

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

For Canadian tax purposes, 82% of distributions declared in 2009 were taxable as income, unless held in a registered plan. The remaining 18% of distributions were classified as a return of capital. Additional tax information is available on our website.

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 acquisitions, and repay bank debt. Net income includes significant non-cash charges that do not affect cash flow. These charges amounted to \$15.8 million for the fourth quarter of 2009 (2008 – \$13.7 million) and \$63.5 million for the year 2009 (2008 – \$61.9 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, except as noted)	Three Months Ended December 31		Twelve Months Ended December 31	
	2009	2008	2009	2008
Cash provided by operating activities	25,937	41,672	95,659	179,252
Net income	14,721	13,374	31,741	109,956
Distributions declared	23,937	54,387	70,480	143,749
Excess (shortfall) of cash provided by operating activities over distributions declared	8%	(23%)	36%	25%
Shortfall of net income over distributions declared	(39%)	(75%)	(55%)	(24%)

UNITHOLDERS' CAPITAL

On October 26, 2009, the Board of Directors approved the monthly issuance of Trust Units from treasury for the Distribution Reinvestment Plan (DRIP), effective for the October distribution payable on November 15, 2009 and thereafter. Previously, Trust Units issued in relation to the DRIP were purchased through the facilities of the Toronto

Stock Exchange at prevailing market prices. For the three and twelve months ended December 31, 2009, Freehold issued 260,740 Trust Units. The ascribed value of \$3.9 million is based on the weighted average closing price for the 10 trading days preceding each distribution date.

CN Pension Trust Funds, which owns approximately 23% of our Trust Units, began participating in the DRIP, effective with the distribution paid on November 15, 2009. With a higher participation rate in the DRIP and by issuing Trust Units from treasury instead of purchasing them in the market, we have a new source of capital, which can be used to develop our working interest properties, reduce long-term debt, or fund acquisitions.

On December 10, 2009, Freehold closed an equity offering and issued 7,618,750 Trust Units at \$15.15 per Trust Unit for gross proceeds of \$115.4 million. The issue costs, including underwriters fees, were \$4.9 million with net proceeds being \$110.5 million.

During the fourth quarter, 41,635 Trust Units were issued from treasury for Management Fees. As at December 31, 2009 there were 57,502,943 Trust Units outstanding and as at March 3, 2010, there were 57,761,762 Trust Units outstanding.

During the fourth quarter, 331 deferred trust units were granted (see Unit Based and Other Compensation). As at December 31, 2009, there were 53,070 deferred trust units outstanding and at March 3, 2010, there were 68,083 deferred trust units outstanding.

TRUST UNITS OUTSTANDING	Three Months Ended			Twelve Months Ended		
	December 31			December 31		
	2009	2008	Change	2009	2008	Change
Weighted average						
Basic	51,483,092	49,424,163	4%	49,999,617	49,370,878	1%
Diluted	51,519,581	49,466,965	4%	50,053,435	49,412,670	1%
At period end	57,502,943	49,459,429	16%	57,502,943	49,459,429	16%

Critical Accounting Estimates

The assets, liabilities, revenues, and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, and oil and gas revenue accruals. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Except as discussed in this MD&A, we are not aware of any trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

New Accounting Standards

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

As discussed in our 2008 annual MD&A, we are continuing to prepare for the adoption of IFRS effective January 1, 2011. In preparation for the transition from current Canadian GAAP to IFRS, we have assigned internal staff to lead the conversion project, retained an external advisor to assist us, and continue to involve our auditors in the process. Our transition plan addresses resources required; employee training; analysis of accounting standard differences; accounting policy determination; evaluation of information system requirements; and an impact assessment on operations, internal controls over financial reporting, and disclosures.

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

- For property, plant and equipment, we have decisions to make under IAS 16 regarding asset valuation, cash generating units, and depletion and depreciation. Under IFRS 1, we have an option to record opening values at their deemed cost, which is the net book value under Canadian GAAP at January 1, 2010, rather than retrospectively applying the requirements of IAS 16.
- We need to determine if Freehold has any exploration and evaluation assets and whether these assets need to be broken down into cash generating units. A policy will have to be formulated as to when these assets will be transferred to being treated under IAS 16 rather than IFRS 6. The original valuation of these assets can be affected by IFRS 1 where there is an option to use their deemed cost, which is the net book value under Canadian GAAP at January 1, 2010.
- Impairment testing for Freehold's property, plant and equipment and exploration and evaluation assets will have to occur at a cash generating unit. Impairment is tested at reporting dates if there is an indication that an asset may be impaired. Impairments may be reversed if the impairment indicators have reversed.
- For our asset retirement obligations, we have an option under IFRS 1 to revalue our obligation at January 1, 2010 using the appropriate discount rate at that date, rather than retrospectively revaluing each year as required under IAS 37.
- For share-based payments, we have an option not to apply IFRS 2 retrospectively if, by January 1, 2010, equity settled instruments were fully vested or cash settled payments were transacted.
- There are considerations to be made as to the potential treatment of Trust Units under IAS 32.

We will continue to monitor all business agreements, including lending agreements, to ensure that they remain unaffected by the changeover to IFRS. Information technology systems are being evaluated and appear to be adequate with minor modifications. Internal controls over financial reporting will be assessed as accounting policy choices are finalized to ensure that additional controls and procedures are in place for future reporting requirements. Disclosure controls and procedures will also be evaluated to ensure that we keep stakeholders' informed about the transition. We plan to make final decisions on accounting policies, information technology requirements and training requirements by the third quarter of 2010, while internal controls and disclosures issues will not be finalized until early in 2011.

We will provide progress updates on our IFRS conversion project in our quarterly MD&A.

FINANCIAL INSTRUMENTS – DISCLOSURES

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

Related Party Transactions

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

For the three months ended December 31, 2009, Freehold issued 41,635 Trust Units (2008 – 35,654 Trust Units) as a management fee to the Manager pursuant to a management agreement. The ascribed value of \$0.6 million (2008 – \$0.4 million) is based on the closing price of the Trust Units on the last trading day of the quarter. The total issued for the twelve months ended December 31, 2009 was 148,597 Trust Units (2008 – 142,616) with an ascribed value of \$2.0 million (2008 – \$2.5 million).

For the three months ended December 31, 2009, the Manager charged the Trust \$1.1 million in general and administrative costs (2008 – \$1.1 million). The total for the twelve months ended December 31, 2009 was \$5.7 million (2008 – \$5.3 million). At December 31, 2009, there was \$0.4 million (2008 – \$nil) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was the amount of consideration established and agreed to by the Trust and the Manager.

Contingencies

In the second quarter of 2009, a statement of claim was filed against the Trust for \$9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, the Trust has assessed the claim, believes it has no merit, and intends to aggressively defend itself in the claim. The claim's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

In the fourth quarter of 2009, a judgment of \$2.1 million in Freehold's favour was received and recorded in other income. The claim was based on Freehold's assertion of incorrect royalty payments and production from a terminated lease. Cash payment in full was received subsequent to year-end. The defendant has appealed this judgment but Freehold and its legal counsel believe there are no grounds for a successful appeal. The appeal's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

Consolidated Balance Sheets

(\$000s) (unaudited)	December 31 2009	December 31 2008
Assets		
Current assets:		
Cash	\$ 432	\$ 537
Accounts receivable	24,056	23,261
	24,488	23,798
Reclamation fund	2,261	1,827
Deferred long-term compensation (note 6)	1,954	120
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$513,139 (2008 - \$450,079)	389,837	426,530
	\$ 418,540	\$ 452,275
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	\$ 8,050	\$ 29,676
Accounts payable and accrued liabilities	17,877	14,094
Current portion of unit based and other compensation payable (note 6)	1,643	83
	27,570	43,853
Asset retirement obligation	7,160	5,663
Unit based and other compensation payable (note 6)	3,702	243
Long-term debt (note 3)	45,000	140,000
Future income tax liability	36,136	42,511
Unitholders' equity:		
Unitholders' capital (note 4)	684,979	567,310
Contributed surplus (note 6)	759	722
Deficit	(386,766)	(348,027)
	298,972	220,005
	\$ 418,540	\$ 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 December 31		Year Ended December 31	
	2009	2008	2009	2008
Revenue:				
Royalty income and working interest sales	\$ 35,167	\$ 34,461	\$ 119,965	\$ 204,116
Royalty expense and mineral tax	(1,201)	(1,287)	(2,733)	(6,616)
	33,966	33,174	117,232	197,500
Other income (note 8)	2,122	-	2,122	-
Expenses:				
Operating	2,876	3,015	11,655	11,299
General and administrative	1,622	1,574	7,234	6,790
Unit based and other compensation (note 6)	876	(861)	3,718	97
Interest and financing	1,049	1,391	4,678	7,039
Depletion and depreciation	15,780	16,076	63,060	67,948
Accretion of asset retirement obligation	87	96	333	384
Management fee (note 5)	628	374	2,018	2,482
	22,918	21,665	92,696	96,039
Income before taxes	13,170	11,509	26,658	101,461
Income and capital taxes	(47)	165	255	398
Future income tax reduction	(1,504)	(2,030)	(5,338)	(8,893)
	(1,551)	(1,865)	(5,083)	(8,495)
Net income and comprehensive income	14,721	13,374	31,741	109,956
Deficit, beginning of period	(377,550)	(307,014)	(348,027)	(314,234)
Distributions declared	(23,937)	(54,387)	(70,480)	(143,749)
Deficit, end of period	\$ (386,766)	\$ (348,027)	\$ (386,766)	\$ (348,027)
Net income per Trust Unit, basic and diluted	\$ 0.29	\$ 0.27	\$ 0.63	\$ 2.23
Weighted average number of Trust Units:				
Basic	51,483,092	49,424,163	49,999,617	49,370,878
Diluted	51,519,581	49,466,965	50,053,435	49,412,670

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Cash Flows

(\$000s) (unaudited)	Three Months Ended December 31		Year Ended December 31	
	2009	2008	2009	2008
Cash provided by (used in):				
Operating:				
Net income	\$ 14,721	\$ 13,374	\$ 31,741	\$ 109,956
Items not involving cash:				
Depletion and depreciation	15,780	16,076	63,060	67,948
Unit based and other compensation (note 6)	777	(861)	3,444	7
Future income tax reduction	(1,504)	(2,030)	(5,338)	(8,893)
Accretion of asset retirement obligation	87	96	333	384
Trust Units issued in lieu of management fee	628	374	2,018	2,482
Expenditures on reclamation	(45)	(87)	(173)	(602)
	30,444	26,942	95,085	171,282
Changes in non-cash working capital	(4,507)	14,730	574	7,970
	25,937	41,672	95,659	179,252
Financing:				
Issue of Trust Units, net of issue costs	110,486	-	110,486	-
Long-term debt	(102,000)	(1,000)	(95,000)	(38,000)
Distributions paid	(17,931)	(37,068)	(88,200)	(121,471)
	(9,445)	(38,068)	(72,714)	(159,471)
Investing:				
Property and royalty acquisitions	(9,539)	782	(9,539)	(7,693)
Capital expenditures	(4,435)	(3,770)	(15,491)	(12,992)
Change in reclamation fund	(104)	(71)	(434)	(39)
Changes in non-cash working capital	(2,293)	(220)	2,414	1,087
	(16,371)	(3,279)	(23,050)	(19,637)
Increase (decrease) in cash	121	325	(105)	144
Cash, beginning of period	311	212	537	393
Cash, end of period	\$ 432	\$ 537	\$ 432	\$ 537

See accompanying notes to interim consolidated financial statements.

Notes to Interim Consolidated Financial Statements

For the three and twelve months ended December 31, 2009 and 2008.

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. In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal recurring nature necessary to present fairly the Trust's financial position as at December 31, 2009 and the results of its operations and cash flows for the three and twelve months then ended.

Financial Instruments – Disclosures

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

New Accounting Policy

The Trust funds its proportionate share of a retirement benefit for certain employees of the Manager, upon fulfilling certain criteria. The Trust accrues its share of the post retirement costs over the service life of the employees.

2. Property Acquisition

On December 21, 2009, Freehold closed an acquisition of certain royalty interests in Alberta for \$10.0 million, including adjustments. The acquisition was effective July 1, 2009 and was funded through existing credit facilities. During 2009, Freehold also recovered \$0.5 million (2008 - \$0.8 million) of prior year acquisition adjustments.

3. Long-Term Debt

Freehold has a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which \$45 million was drawn at December 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 lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice. The facilities are extendible annually with the latest review completed in May 2009. In the event that the lenders do not consent to an extension, the revolving credit facility would revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period, which is May 2010.

Borrowings under the facilities bear interest at the bank's prime lending rate, banker's acceptance or LIBOR rates plus applicable margins, ranging from 150 to 300 basis points, and standby fees. The fair value of the long-term debt was determined using quoted borrowing rates and therefore was considered level 2. At December 31, 2009, the fair value of the long-term debt approximated its carrying value.

Freehold's borrowing base is dependent on the lenders' annual review and interpretation of our reserves and future commodity prices, with the next renewal to occur by May 2010.

4. Unitholders' Capital

	December 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 (note 5)	148,597	2,018	142,616	2,482
Issued for director's retirement (note 6)	15,427	222	-	-
Issued for Distribution Reinvestment Plan	260,740	3,906	-	-
Issued for equity offering, net of issue costs	7,618,750	115,424	-	-
Issue costs, net of tax effect	-	(3,901)	-	-
Balance, end of period	57,502,943	684,979	49,459,429	567,310

On December 10, 2009, Freehold closed an equity offering and issued 7,618,750 units at a price of \$15.15 per Trust Unit for gross proceeds of \$115.4 million. The issue cost including underwriters fees were \$4.9 million (\$3.9 million net of tax effect) with net proceeds being \$110.5 million.

On October 26, 2009, the Board of Directors approved the monthly issuance of Trust Units from treasury for the Distribution Reinvestment Plan (DRIP), effective for the October distribution payable on November 15, 2009 and thereafter. Previously, Trust Units issued in relation to the DRIP were purchased through the facilities of The Toronto Stock Exchange at prevailing market prices. For the three and twelve months ended December 31, 2009, Freehold issued 260,740 Trust Units. The ascribed value of \$3.9 million is based on the weighted average closing price for the 10 trading days preceding each distribution date.

5. Related Party Transactions

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

For the three months ended December 31, 2009, Freehold issued 41,635 Trust Units (2008 – 35,654 Trust Units) as a management fee to the Manager pursuant to a management agreement. The ascribed value of \$0.6 million (2008 – \$0.4 million) is based on the closing price of the Trust Units on the last trading day of the quarter. The total issued for the twelve months ended December 31, 2009 was 148,597 Trust Units (2008 – 142,616) with an ascribed value of \$2.0 million (2008 – \$2.5 million).

For the three months ended December 31, 2009, the Manager charged the Trust \$1.1 million in general and administrative costs (2008 – \$1.1 million). The total for the twelve months ended December 31, 2009 was \$5.7 million (2008 – \$5.3 million). At December 31, 2009, there was \$0.4 million (2008 – \$nil) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was the amount of consideration established and agreed to by the Trust and the Manager.

6. Unit Based and Other Compensation

(a) Manager's Long-Term Incentive Plan

After a three-year vesting period, employees of the Manager receive cash compensation in relation to the value of a specified number of notional units. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. For the three months ended December 31, 2009, Freehold expensed \$344,000 (2008 – \$893,000 recovered) as unit based compensation. The total for the twelve months ended December 31, 2009 was \$2,862,000 (2008 – \$203,000 recovered). At December 31, 2009, Freehold recorded \$1,954,000 (2008 – \$120,000) as a deferred long-term compensation asset, representing the portion of the liability not yet charged to earnings. In addition, Freehold accrued \$3,395,000 (2008 – \$243,000) as a long-term liability and \$1,545,000 (2008 – \$83,000) as a current liability.

(b) Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. As at December 31, 2009, there were 53,070 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement. For the twelve months ended December 31, 2009, 22,038 deferred trust units were redeemed upon a director's retirement, resulting in the issuance of 15,427 Trust Units from treasury. In payment of withholding tax, 6,611 deferred trust units were cancelled and the cash value remitted to Canada Revenue Agency.

For the three months ended December 31, 2009, Freehold expensed \$28,000 (2008 – \$32,000) of unit based compensation with a corresponding increase to contributed surplus. The total for the twelve months ended December 31, 2009 was \$352,000. For the twelve months ended December 31, 2008, the Trust expensed \$300,000 as unit based compensation. The corresponding increase to contributed surplus for the twelve months ended December 31, 2008 was \$210,000 as \$90,000 was a cash expense for the cancellation of deferred trust units.

CONTRIBUTED SURPLUS (\$000s)	December 31 2009	December 31 2008
Balance, beginning of period	722	512
Trust Unit incentive compensation expense	352	210
Grants redeemed on director's retirement	(315)	-
Balance, end of period	759	722

(c) Retirement Benefit

In 2009, the Trust agreed to participate in its proportionate share of a retirement benefit for certain employees of the Manager. The retirement benefit is payable in four equal instalments upon retirement and reaching the age of 65. Service costs are amortized on a straight-line basis over the expected average remaining service lifetime.

RECONCILIATION OF CHANGES IN THE PLAN'S BENEFIT OBLIGATIONS FOR THE YEAR 2009

(\$000s)	2009	2008
Accrued benefit obligation, beginning of period	-	-
Current service cost	504	-
Payments	(99)	-
Accrued benefit obligation, end of period	405	-

7. Supplemental Cash Flow Disclosure

CASH EXPENSES PAID (\$000s)	Three Months Ended December 31		Twelve Months Ended December 31	
	2009	2008	2009	2008
Interest	803	1,118	4,375	6,753
Taxes	101	73	494	329

8. Contingencies

In the second quarter of 2009, a statement of claim was filed against the Trust for \$9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, the Trust has assessed the claim, believes it has no merit, and intends to aggressively defend itself in the claim. The claim's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

In the fourth quarter of 2009, a judgment of \$2.1 million in Freehold's favour was received and recorded in other income. The claim was based on Freehold's assertion of incorrect royalty payments and production from a terminated lease. Cash payment in full was received subsequent to year-end. The defendant has appealed this judgment but Freehold and its legal counsel believe there are no grounds for a successful appeal. The appeal's outcome is not determinable; therefore, no liability has been recorded in the financial statements.

9. Subsequent Event

On February 17, 2009, Freehold closed an acquisition of certain royalty interests in Alberta, Saskatchewan, and British Columbia for \$39 million, after closing adjustments. The acquisition was effective October 1, 2009 and was funded through existing credit facilities.

Corporate Information

BOARD OF DIRECTORS

D. Nolan Blades ⁽¹⁾⁽²⁾⁽³⁾
 President
 Sunny Gables Holdings Ltd.

Harry S. Campbell, Q.C. ⁽³⁾⁽⁴⁾⁽⁵⁾
 Vice-Chair
 Burnet, Duckworth & Palmer, LLP

Tullio Cedraschi ⁽³⁾⁽⁴⁾
 Corporate Director

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

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

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

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

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

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

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

OFFICERS

D. Nolan Blades
 Chair of the Board

William O. Ingram
 President and Chief Executive Officer

Michael J. Okrusko
 Senior Vice-President, Special Projects

Garry W. Bieber
 Vice-President, Production

J. Frank George
 Vice-President, Exploitation

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

Michael J. Stone
 Vice-President, Land

Michael J. Mogan
 Controller

Karen C. Taylor
 Manager, Investor Relations and
 Corporate Secretary

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

Karen C. Taylor
 Manager, Investor Relations and
 Corporate Secretary
 Telephone: (403) 221-0891
 Toll Free: 1-888-257-1873
 Email: ir@freeholdtrust.com

WEBSITE

www.freeholdtrust.com

2009 FOURTH QUARTER
 TRADING SUMMARY

High – \$16.28
 Low – \$14.02
 Close – \$15.09
 Volume Traded – 6.8 million
 Trust Units Outstanding – 57.5 million

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

2009 FOURTH QUARTER
 DISTRIBUTIONS DECLARED

<u>Record Date</u>	<u>Payment Date</u>	<u>Per Trust Unit</u>
Oct. 31, 2009	Nov. 15, 2009	\$0.12
Nov. 30, 2009	Dec. 15, 2009	\$0.20 *
Dec. 31, 2009	Jan. 15, 2010	<u>\$0.14</u>
		<u>\$0.46</u>

* includes additional distribution of
 \$0.06 per Trust Unit for 2009.

Tax information and historical
 distributions are available on our
 website.