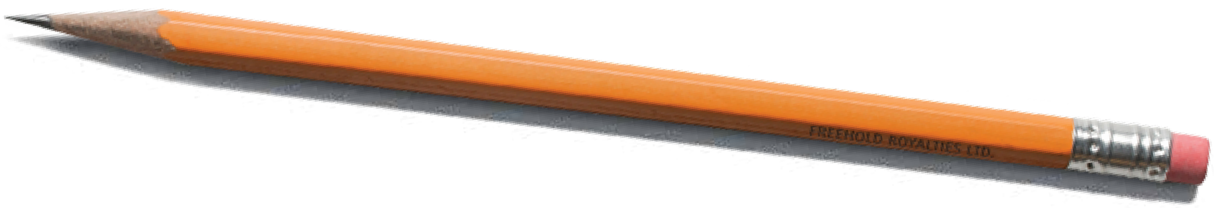
2010 Financial Report



Freehold
ROYALTIES LTD.

BUSINESS AS USUAL

Freehold Royalties Ltd.

CONTENTS

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) was prepared as of March 2, 2011, and is management's opinion about the consolidated operating and financial results of Freehold Royalties Ltd. and its wholly-owned subsidiaries for the year ended December 31, 2010 and previous periods, and the outlook for Freehold based on information available as of the date hereof.

The financial information contained herein is based on information in the consolidated financial statements, which have been prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). All comparative percentages are between the years ended December 31, 2010 and 2009, and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This MD&A should be read in conjunction with the audited financial statements and notes. Discussion and analysis of fourth quarter events or items affecting our financial condition, cash flows, and results of operations is contained in our 2010 fourth quarter MD&A, which is incorporated by reference herein. Additional information about us, including our annual information form (AIF), is available on SEDAR at www.sedar.com and on our website at www.freeholdroyalties.com.

This MD&A contains Non-GAAP measures and forward-looking statements; readers are cautioned that the MD&A should be read in conjunction with our disclosure under "Non-GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

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Corporate Conversion

Freehold Royalties Ltd. (Freehold) is incorporated under the laws of the Province of Alberta and trades on the Toronto Stock Exchange under the symbol FRU.

Freehold resulted from a reorganization, effective December 31, 2010, pursuant to a Plan of Arrangement (the Reorganization) approved by the unitholders at a special meeting held on December 10, 2010. The Reorganization involved Freehold Royalty Trust (the Trust), Freehold Royalties Ltd., Freehold Resources Ltd., Freehold Royalties Partnership (a general partnership previously named Petrovera Resources) and the Trust's unitholders, among others. As part of the Reorganization, the Trust was restructured from an open-ended investment trust to a dividend-paying corporation. All outstanding trust units were exchanged for common shares on the basis of one common share for each trust unit held. Freehold's business activities and management did not change as a result of the Reorganization.

The Reorganization was accounted for on a continuity-of-interest basis. Therefore, the consolidated financial statements for periods prior to the Reorganization reflect Freehold's financial position, results of operations and cash flows as if it had always carried on the business formerly carried on by the Trust.

This MD&A includes information with respect to the Trust prior to the Reorganization. In this MD&A, references to common shares, shares, shareholders and dividends can be interpreted as trust units, units, unitholders and distributions for periods prior to December 31, 2010, as the context may require.

Business Overview

Freehold is directly and indirectly involved in the development and production of oil and natural gas predominantly in western Canada. We receive revenue from oil and natural gas properties as reserves are produced over the economic life of the properties. Our primary focus is acquiring and managing oil and gas royalties.

Strategy

We effectively manage our assets to consistently deliver attractive returns to shareholders. Our goal is to be recognized as the preeminent royalty-focused oil and gas investment in Canada. We employ the following strategies to sustain production and extend reserve life:

- Maintain an aggressive audit program to ensure that royalties are correctly calculated and collected.
- Pursue development opportunities to optimize reserves and production on our working interest properties.
- Acquire additional assets with a bias toward royalty interests.
- Maintain a conservative capital structure to provide maximum financial flexibility with respect to acquisitions and development expenditures, while maintaining an appropriate dividend payout level.

The Royalty Advantage

We manage one of the largest non-governmental portfolios of oil and gas royalties in Canada. Our royalty lands are geographically widespread, extending from northeastern British Columbia to southern Ontario. At December 31, 2010, our royalty land holdings encompassed approximately 2.6 million acres including over 750,000 acres of undeveloped land. Our mineral title lands (including royalty assumption lands), which we own in perpetuity, cover 640,000 acres. In addition, we have gross overriding royalty interests on over 1.9 million acres.

We have royalty interests in more than 26,000 wells and we receive royalty income from over 200 industry operators. Royalty rates vary from less than 1% (for some gross overriding royalties) to 22.5% (for some lessor royalties). This diversity lowers our risk. Royalties offer the benefit of sharing in production revenue without exposure to the capital costs, operating costs, and environmental costs typically associated with oil and gas operations. On the majority of our production, we receive royalty income from gross production revenue (revenue before any royalty expenses and operating costs are deducted). Our high percentage of royalty production (73% in 2010) results in strong netbacks.

We also hold working interests in 211,000 gross (25,981 net) acres. The majority of our working interest production comes from three properties in Alberta and Saskatchewan. We have various working interests in 96 other properties, which individually contribute less than 100 boe per day.

The accompanying netback analysis demonstrates the positive effect of the royalty advantage on our cash margins, as production on our royalty lands yields higher operating netbacks than our working interest properties.

2010 NETBACK ANALYSIS

($000s)	Royalty Interest	Working Interest	Total
Gross revenue (1)	95,758	42,397	138,155
Royalty expense and mineral tax (2)	(194)	(3,898)	(4,092)
Net revenue	95,564	38,499	134,063
Operating expense	-	(11,569)	(11,569)
	95,564	26,930	122,494

($ per boe)			
Gross revenue (1)	47.08	56.88	49.71
Royalty expense and mineral tax (2)	(0.10)	(5.23)	(1.47)
Net revenue	46.98	51.65	48.24
Operating expense	-	(15.52)	(4.16)
Operating netback (3)	46.98	36.13	44.08

(1) Gross revenue includes potash, sulphur, lease rentals, processing fees, and interest income; excludes other income/expense.
(2) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.
(3) Operating netback is calculated by subtracting royalty and operating expenses from gross revenue.

OPERATING NETBACK

($ per boe)	2010	2009	2008
Royalty interest	46.98	43.59	69.33
Working interest	36.13	30.12	55.00
Total (1)	44.08	39.61	65.18

(1) 2009 includes a one-time adjustment to operating expense, and a recovery of freehold mineral tax from certain lessees. See Operating Expenses and Royalty Expense and Mineral Tax.

The Manager

Freehold does not have any employees. The assets are managed by a wholly-owned subsidiary of Rife Resources Ltd., which is a wholly-owned subsidiary of the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager (Rife) also manages two private companies that are engaged in similar oil and gas operations. To manage these private companies and Freehold, Rife has assembled a larger, more diversified and more experienced staff than we could otherwise retain to manage our assets. Rife also ensures that we receive priority to consider acquisition opportunities. We believe these organizational and synergistic benefits are advantageous to our shareholders. In addition, the management fees are paid in shares, which we believe aligns the interests of the Manager with the interests of our shareholders.

The Manager is responsible for the day-to-day management of our business subject to the supervisory role of the Freehold Board. In particular, the Board makes significant operational decisions and all decisions relating to: (a) issuances of additional securities; (b) acquisition and disposition of properties in excess of $5 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities; and (e) payment of dividends.

The Manager provides certain services for a fee based on a specified number of shares per quarter, pursuant to the amended and restated management agreement, which has a three-year term and will automatically renew in November 2013, unless terminated. In exercising its powers and discharging its duties under the management agreement, the Manager must exercise the degree of care, diligence, and skill that a reasonably prudent advisor and manager in respect of petroleum and natural gas properties in western Canada would exercise in comparable circumstances. The Manager recovers its general and administrative costs and a portion of its long-term incentive plan costs and retirement benefit costs, and receives a quarterly management fee paid in shares (see Related Party Transactions).

The Manager provides certain administrative and support services, including those necessary to:

- Ensure compliance with continuous disclosure obligations under applicable securities legislation.
- Provide investor relations services.
- Provide to shareholders all information to which they are entitled under applicable corporate and securities laws.

- Call, hold, and distribute materials including notices of meetings and information circulars in respect of all necessary meetings of shareholders.
- Determine the amounts available for payment and arrange for dividend payments to shareholders.
- Determine the timing and terms of future offerings of securities, if any.
- Determine the terms and conditions upon which Freehold may acquire additional assets.
- Determine the terms and conditions upon which Freehold may from time to time borrow money.

Outlook

Business Environment

The global economy, emerging from the worst recession in decades, grew almost 5% in 2010. Rising demand for commodities led to a 29% increase in WTI crude oil prices. However, weakness of the U.S. dollar and wider price differentials for heavy oil in the last half of the year muted the effect of this increase as the benchmark Western Canada Select rose only 15% year-over-year. The pipeline issues that caused heavy oil differentials to soar should not have a permanent affect on pricing, and we believe markets for heavy oil remain positive due to continued strong refinery demand for this product type.

Natural gas prices have not fared so well, as supply continues to outstrip demand in North America. At the peak of the winter heating season, natural gas storage levels remain above the five-year average. Increasing production, due to enhanced drilling and completion techniques, is by far the largest contributor, and while natural gas is an environmentally-friendly, low cost source of fuel, abundant supply combined with lack of demand growth continues to depress prices.

The Canadian Association of Oilwell Drilling Contractors (CAODC) reported a total of 13,566 wells drilled in western Canada (on a “wells completed” basis) in 2010, with a significant shift towards oil-focused investment. The CAODC’s 2011 forecast (issued in October 2010) projects similar activity levels for 2011, and assumes little improvement in natural gas prices.

Horizontal drilling technology is being used to increase production from existing producing formations as well as to access tight reservoirs and other resource plays that were previously uneconomic using traditional vertical drilling techniques. Across our land base, more than half of the wells drilled in 2010 were horizontal wells (38% on our royalty lands). Given our extensive land holdings, almost 2.8 million gross acres spanning much of the Western Canada Sedimentary Basin, we are well positioned to participate in many of these opportunities. The most promising areas for us are on lands situated south of the North Saskatchewan River (in the watershed of the Hudson’s Bay), where we own significant mineral title lands.

When Freehold was formed in 1996, all our royalty lands were leased to third parties and producing. Over the years, our unleased mineral title acreage has grown – through acquisitions, lease expiries, surrenders, and defaults. We now have about 100,000 unleased acres, of which 30,000 acres are prospective for Bakken oil in southeast Saskatchewan. We are proactively working to crystallize the value of this undeveloped acreage through selective lease-outs to industry partners and by investing our own capital in the development of these lands.

2011 Plans

Our Board has approved a capital budget for 2011 of $20 million for the continued development of our working interest properties. About two-thirds of our budget will be spent in Southeast Saskatchewan, including our Bakken-prone title lands where we continue to see opportunities. In the current environment, we are also seeing some interesting acquisition opportunities. While we have not budgeted funds for acquisitions, we have $145 million of available capacity under our credit facilities to take advantage of accretive opportunities.

In 2010, our production averaged just over 7,600 boe per day. Based on our $20 million capital program, conservative estimates of drilling activity on our leased royalty lands, and normal production declines (and excluding any potential acquisitions), we expect production to decline 7% in 2011, to average approximately 7,100 boe per day for the year. Our production remains unhedged, subject to quarterly review by our Board.

Cash preserved through our dividend reinvestment plan (expected to be approximately $27 million for 2011) enhances our ability to fund our capital program, strengthen our balance sheet, and pursue acquisition opportunities, while maintaining an attractive dividend payout ratio.

Our key operating assumptions for 2011 are outlined below.

2011 KEY OPERATING ASSUMPTIONS

As at March 2, 2011		
Average daily production	boe/d	7,100
Average WTI oil price	US$/bbl	80.00
Average exchange rate	Cdn$/US$	0.95
Average heavy oil differential (1)	Cdn$/bbl	(13.00)
Average AECO natural gas price	Cdn$/Mcf	4.25
Average operating costs	$/boe	4.50
Average general and administrative costs (2)	$/boe	3.50
Capital expenditures	$ millions	20
Proceeds from DRIP (3)	$ millions	27
Long-term debt at year end	$ millions	50
Weighted average shares outstanding	millions	60

(1) The difference between the Edmonton Par and Western Canada Select crude oil streams.
(2) Excludes share based and other compensation.
(3) Average 27% participation rate, which is subject to change.

Dividend Policy

As a corporation, our dividend policy will be similar to our distribution policy as a trust, subject to the satisfaction of liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Dividends will continue to be paid monthly, with the Board reviewing the dividend policy quarterly. Under our current production, commodity price, and operating assumptions, we expect to pay a monthly dividend of $0.14 ($1.68 annually) per share in 2011. Future dividend levels will depend on the cash flow generated by Freehold's assets, which can vary depending on a number of factors, including commodity prices, production volumes, foreign exchange rates, capital expenditures, participation levels in the dividend reinvestment plan (DRIP), debt service requirements, costs and corporate tax.

As a corporation, Freehold is subject to corporate taxation. We currently have $235 million in tax pools available to shelter income from cash taxes. As an owner of primarily royalty interests, our ability to generate additional tax pools is limited. We do not expect to pay corporate income tax on income earned in 2011; however, starting in 2012, we expect to be cash taxable at a rate of 15% to 20%, which may reduce the amount available for dividends.

A sensitivity analysis of the potential impact of key variables on funds generated from operations is provided below. For the purposes of the sensitivity analysis, the effect of a variation in a particular variable is calculated independently of any change in another variable. In reality, changes in one factor will contribute to changes in another, which can magnify or counteract the sensitivities. For instance, trends have shown a correlation between the movement in the foreign exchange rate of the Canadian dollar relative to the U.S. dollar and the benchmark WTI crude oil price.

SENSITIVITY ANALYSIS

		Estimated Change in Funds Generated From Operations	
Variable	Change (+/-)	($000s)	($/share)
WTI oil price	US$1.00/bbl	1,700	0.03
Canadian/U.S. dollar exchange rate	US$0.01	1,400	0.02
Light/heavy oil price differential (1)	Cdn$1.00/bbl	1,600	0.03
AECO natural gas price	Cdn$0.25/Mcf	1,400	0.02
Interest rate	1%	600	0.01
Oil and NGL production	100 bbls/d	2,500	0.04
Natural gas production	1,000 Mcf/d	1,500	0.02

(1) The difference between the Edmonton Par and Western Canada Select crude oil streams.

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 dividend rate. 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.

Results of Operations

2010 Highlights

- Gross revenue increased 15%, mainly due to higher oil prices. Average price realizations were $48.74 per boe, up 11%, and average production was 7,615 boe per day, up 4% from 2009.
- Cash provided by operating activities (including changes in non-cash working capital) rose 16%, reflecting higher realized prices and slightly higher production volumes; funds generated from operations rose 13%, and net income rose 14%.
- Distributions for 2010 totalled $1.68 per share, 20% higher than in 2009.
- Net acquisitions (royalty interests) totalled $38.6 million.
- Net capital expenditures (working interests) totalled $18.1 million, or 17% of funds generated from operations.

HIGHLIGHTS

($000s, except as noted)	2010	2009	2008
Gross revenue	138,155	119,965	204,116
Revenue, net of royalty expenses	134,063	117,232	197,500
Net income	36,273	31,741	109,956
Per share, basic and diluted ($)	0.62	0.63	2.23
Cash provided by operating activities	110,693	95,659	179,252
Per share ($)	1.90	1.91	3.63
Funds generated from operations (1)	106,971	95,085	171,282
Per share ($)	1.83	1.90	3.47
Total assets	407,460	418,540	452,275
Long-term debt	65,000	45,000	140,000
Total long-term liabilities	111,775	91,998	188,417
Distributions declared	98,115	70,480	143,749
Per share ($) (2)	1.68	1.40	2.91
Average shares outstanding (000s) (3)	58,334	50,000	49,371

(1) See Non-GAAP Measures.
(2) Based on the number of shares issued and outstanding at each record date.
(3) Weighted average number of shares outstanding during the period, basic. Prior to conversion to a corporation on December 31, 2010, Freehold had trust units outstanding instead of shares.

Compared with last year, our results reflect higher revenues due to higher oil prices and higher royalty production volumes. Per share amounts reflect a 17% increase in the average number of shares outstanding during 2010. The increase stemmed from an equity offering (7.6 million trust units at $15.15 per trust unit) in late 2009, issuances from treasury for the DRIP starting in November 2009 and increases in the quarterly management fee (paid in shares).

Quarterly Performance and Trends

Our performance is directly influenced by commodity prices, which are determined by supply and demand factors, weather, seasonality, global political events, general economic conditions, and changes in Canadian/U.S. dollar exchange rates. Quarterly variances in revenues, net income, cash provided by operating activities, and funds generated from operations are caused mainly by fluctuations in commodity prices and production volumes. Crude oil prices are generally determined by global supply and demand factors, but the variances do not have seasonable predictability. Natural gas prices are 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. The benchmark price fell significantly in the fourth quarter of 2008 as global economic conditions deteriorated. Low prices prevailed through the first quarter of 2009 and then improved through the remainder of 2009. Prices averaged US$79.53 per barrel in 2010 versus US$61.81 per barrel in 2009.
- Fluctuations in US/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. The average exchange rate was $0.9710 in 2010 versus $0.8798 in 2009.
- In 2009, heavy oil differentials were narrower than prior years due to improved transportation and increased U.S. demand for Canadian heavy crude. Differentials widened in the second quarter of 2010, following completion of the linefill for the Keystone pipeline. Prices for heavy oil were also severely affected during the last half of the year by pipeline transportation issues, which created a logjam in western Canada and drove down heavy oil prices. Although the pipelines have now been brought back into service, it will take some time for the supply glut to work its way through the system. Domestic demand for heavy oil is typically highest during the summer paving season.
- AECO natural gas prices also exhibited significant volatility, falling to a 10-year low during the third quarter of 2009. With supply outstripping demand, prices remained very weak through 2010, averaging $4.13 per Mcf for both 2010 and 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 distribution rate in response to changing commodity prices. In 2008, we declared an additional $0.35 per share, which was paid on January 15, 2009. We also declared an additional $0.06 per share for 2009, which was paid on December 15, 2009. In January 2009, we lowered the rate to $0.10 per share. As oil prices strengthened, we increased the rate to $0.12 per share in August 2009, and increased it again in November 2009, to $0.14 per share. This rate was maintained through the remainder of 2009 and 2010.
- Fluctuations in our share price resulted in corresponding changes in share based compensation, which is based in part on the closing share price at each quarter end.
- Under Freehold's DRIP, commencing with the October 2009 dividend (paid on November 15, 2009), we began issuing DRIP shares from treasury instead of purchasing them in the market. Also with the November 15, 2009 payment, CN Pension Trust Funds, which currently owns approximately 25% of Freehold's shares, began to participate in the DRIP. Cash preserved through the DRIP was approximately $6 million per quarter during 2010.
- On December 10, 2009, we closed an equity offering and issued 7.6 million trust units. Net proceeds of $110.5 million were used to reduce long-term debt.
- On December 21, 2009, we closed a $10 million royalty acquisition, and on February 17, 2010, we closed a $39 million royalty acquisition. Both acquisitions were funded through our existing credit facilities.
- Payments under the Manager's LTIP, which are payable in the first quarter every year, reduced cash provided by operating activities and funds generated from operations by $1.5 million in the first quarter of 2010 (Q1 2009 – $81,000).

The accompanying table illustrates the fluctuations experienced over the past eight quarters and the resulting effect on our financial results. Discussion and analysis of fourth quarter events or items affecting our financial condition, cash flows, and results of operations is contained in our 2010 fourth quarter MD&A, which is incorporated by reference herein. Additional information about our quarterly results is provided in our interim reports, copies of which are available on SEDAR and on our website.

QUARTERLY TRENDS

	2010				2009			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial ($000s, except as noted)								
Revenue, net of royalty expense	35,525	31,732	31,524	35,282	33,966	29,435	28,516	25,315
Distributions declared	24,797	24,617	24,436	24,265	23,937	16,850	14,852	14,841
Per share ($) (1) (2)	0.42	0.42	0.42	0.42	0.46	0.34	0.30	0.30
Net income	10,419	8,966	9,214	7,674	14,721	7,853	6,776	2,391
Per share, basic and diluted ($)	0.18	0.15	0.16	0.13	0.29	0.16	0.14	0.05
Cash provided by operating activities	28,015	26,704	28,757	27,217	25,937	26,215	21,938	21,569
Per share ($)	0.48	0.46	0.49	0.47	0.50	0.53	0.44	0.44
Funds generated from operations (3)	28,218	25,811	25,197	27,745	30,444	24,189	21,833	18,619
Per share ($)	0.48	0.44	0.43	0.48	0.59	0.49	0.44	0.38
Property and royalty acquisitions (net)	283	(153)	71	38,399	9,539	-	-	-
Capital expenditures	4,664	6,003	4,735	2,652	4,435	7,368	1,661	2,027
Long-term debt	65,000	70,000	73,000	78,000	45,000	147,000	156,000	160,000
Shares outstanding								
Weighted average (000s)	58,972	58,536	58,112	57,700	51,483	49,543	49,495	49,460
At quarter end (000s)	59,181	58,781	58,335	57,926	57,503	49,582	49,531	49,495
Operating ($/boe, except as noted)								
Daily production (boe/d)	7,972	7,495	7,655	7,331	7,402	6,994	7,295	7,522
Royalty interest production (%)	74	73	73	73	69	71	71	70
Average selling price	48.80	46.44	45.56	54.45	51.09	44.01	42.99	37.85
Operating netback (3)	44.57	41.56	40.96	49.44	45.66	42.16	37.56	33.13
Operating expenses	3.87	4.46	4.29	4.03	4.22	3.59	5.39	4.27
Working interest properties	14.72	16.27	15.99	15.10	13.69	12.59	18.78	14.27
Net general and administrative expenses (4)	2.27	2.67	2.56	3.81	2.38	2.35	2.12	3.98
Benchmark Prices								
WTI crude oil (US$/bbl)	85.16	76.16	78.03	78.71	76.19	68.30	59.62	43.08
Exchange rate (US$/Cdn$)	0.99	0.96	0.97	0.96	0.95	0.91	0.86	0.80
Edmonton Par crude oil (Cdn$)	80.33	74.44	75.19	80.08	76.56	71.50	65.90	49.66
Western Canada Select (Cdn$/bbl)	67.86	62.91	65.62	72.54	67.65	63.75	60.71	42.54
Light/heavy oil differential (Cdn$/bbl) (5)	12.47	11.53	9.57	7.54	8.91	7.75	5.19	7.12
AECO natural gas (Cdn$/Mcf)	3.58	3.71	3.86	5.36	4.23	3.02	3.66	5.62
Share Trading Performance								
High ($)	21.14	17.90	18.05	17.59	16.28	17.00	15.18	11.76
Low ($)	17.75	15.73	15.31	15.08	14.02	12.75	8.70	6.87
Close ($)	20.49	17.89	15.84	16.94	15.09	16.24	13.85	8.90
Volume (000s)	7,279	4,515	6,029	7,943	6,827	5,131	8,756	9,310

(1) Based on the number of shares issued and outstanding at each record date. Prior to conversion to a corporation on December 31, 2010, Freehold had trust units outstanding instead of shares.
(2) The fourth quarter of 2009 includes an additional distribution of $0.06 per trust unit relating to excess income earned during the year.
(3) See Non-GAAP Measures.
(4) Excludes share based and other compensation.
(5) The difference between the Edmonton Par and Western Canada Select crude oil streams.

Revenues

Production

We have no operational control over our royalty lands. As we hold primarily small royalty interests in over 26,000 wells, obtaining timely production data from the well operators is extremely difficult. Thus, we use government reporting databases and past production receipts to estimate revenue accruals. Due to the large number of wells in which we have royalty interests, the nature of royalty interests, and the lag in receiving production receipts, our reported royalty volumes usually include adjustments for prior periods.

On a boe basis, our production was up 4% in 2010, as drilling activity and acquisitions in late 2009 and early 2010 helped to offfset natural production declines on our royalty lands. Royalty interests contributed 73% of total volumes produced in 2010. Effective January 1, 2010, we adjusted our method of allocating royalty interest and working interest production on certain properties where we have both a royalty interest and a working interest. This change affects the comparability of prior period results. The adjustment effectively increased royalty production by approximately 190 boe per day for 2010, reducing working interest volumes by the same amount. Working interest volumes were also affected by declining oil volumes at Hayter, where our infill drilling program, now in its tenth year, is yielding less production.

Our production mix for the year was approximately 38% natural gas and 62% liquids (30% heavy oil, 27% light and medium oil, and 5% NGL).

PRODUCTION SUMMARY

(boe/d)	2010	2009	2008
Royalty interest	5,573	5,147	5,546
Working interest	2,042	2,155	2,258
Total	7,615	7,302	7,804

AVERAGE DAILY PRODUCTION BY PRODUCT TYPE

	2010	2009	2008
Light and medium oil (bbls/d)	2,073	1,999	2,035
Heavy oil (bbls/d)	2,279	2,377	2,533
NGL (bbls/d)	352	323	337
Total oil and NGL (bbls/d)	4,704	4,699	4,905
Natural gas (Mcf/d)	17,465	15,615	17,399
Oil equivalent (boe/d)	7,615	7,302	7,804
Total annual production (Mboe)	2,779	2,665	2,856
Potash (tonnes/d)	11.5	5.1	11.9

PRODUCTION RECONCILIATION

(boe/d)	Royalty Interest	Working Interest	Total
2009 average daily production rate	5,147	2,155	7,302
2009 activities, full year impact	460	460	920
2010 development	350	245	595
2010 acquisitions	375	0	375
Natural decline	(759)	(818)	(1,577)
2010 average daily production rate	5,573	2,042	7,615

Product Prices

The following table is a summary of average benchmark prices.

AVERAGE BENCHMARK PRICES (1)

	2010	2009	2008
WTI crude oil (US$/bbl)	79.53	61.81	99.64
Exchange rate (US$/Cdn$)	0.97	0.88	0.94
Edmonton Par crude oil (Cdn$/bbl)	77.50	65.90	102.16
Western Canada Select (Cdn$/bbl)	67.23	58.66	82.90
Light/heavy oil differential (Cdn$/bbl) (2)	10.27	7.24	19.26
AECO natural gas (Cdn$/Mcf)	4.13	4.13	8.13

(1) Source for commodity prices: Canadian Association of Petroleum Producers.
(2) The difference between the Edmonton Par and Western Canada Select crude oil streams.

Western Canada Select (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.

Our average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average price realizations were 11% higher in 2010 because of higher average oil prices, despite a weaker U.S. dollar and widening heavy oil differentials during the year. Due to extremely low natural gas prices in 2009 and 2010, 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

	2010	2009	2008
Oil ($/bbl)	66.54	57.24	83.45
NGL ($/bbl)	51.33	41.93	67.60
Oil and NGL ($/bbl)	65.40	56.19	82.36
Natural gas ($/Mcf)	3.64	3.67	8.15
Oil equivalent ($/boe)	48.74	44.00	69.93
Potash ($/tonne)	400.90	832.36	613.33

Marketing and Hedging

Our production remain unhedged in 2010, and we have no plans to enter into any foreign currency or commodity price hedges at this time. This policy is subject to quarterly review by our Board.

Royalty Production

Our royalty lands consist of a large number of properties with generally small volumes per property. A provision of most leases calls for our natural gas to be marketed with the lessees' production. Historically, we have chosen to market our oil production in the same manner. Some of our leases allow us to take our oil production in-kind. As at December 31, 2010, we were marketing approximately 40% of our royalty oil production using 30-day contracts.

Working Interest Production

We market 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, and the balance (80%) is marketed with the operators' production.

Revenue and Other Income

Gross revenue in 2010 was 15% higher than in 2009, due to higher realized oil prices and, to a lesser extent, higher royalty production volumes. In December 2009, a judgment of $2.1 million in Freehold's favour was received. The claim was based on Freehold's assertion of incorrect royalty payments and production from a terminated lease. Cash payment in full was received and recorded as income in 2009. In 2010, the defendant appealed the judgement. Upon ruling of the appeal in February 2011, the amount of damages was reduced and Freehold is to refund approximately $1.9 million. The liability and expense are represented in our December 31, 2010 financial statements.

REVENUE AND OTHER INCOME/EXPENSE

($000s)	2010	2009	2008
Gross revenue	138,155	119,965	204,116
Royalty and mineral tax expense (1)	(4,092)	(2,733)	(6,616)
Net revenue	134,063	117,232	197,500
Other income (expense)	(1,850)	2,122	-

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

The accompanying table demonstrates the net effect of price and volume variances on gross revenue. Oil prices accounted for the bulk of the positive variance in 2010.

GROSS REVENUE VARIANCES

($000s)	2010 vs. 2009	2009 vs. 2008	2008 vs. 2007
Oil and NGL			
Production increase (decrease)	109	(4,477)	(13,510)
Price increase (decrease)	15,804	(46,976)	55,199
Net increase (decrease)	15,913	(51,453)	41,689
Natural gas			
Production increase (decrease)	2,456	(2,450)	(3,738)
Price increase (decrease)	(162)	(28,559)	11,473
Net increase (decrease)	2,294	(31,009)	7,735
Other revenue increase (decrease) (1)	(17)	(1,689)	2,508
Gross revenue increase (decrease)	18,190	(84,151)	51,932

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

Expenses

Royalty Expense and Mineral Tax

Oil and gas producers pay royalties to the owners of mineral rights from whom they have acquired leases. These are paid to the Crown (provincial and federal governments) and freehold mineral title owners. Crown royalty rates are tied to commodity prices and the level of oil and gas sales. Crown royalty rates were generally higher in 2010 due to higher oil prices.

We do not incur royalty expense on production from our royalty interest lands. As the royalty owner, we receive the royalty as income from other companies. Mineral tax is payable annually to the Crown. Mineral tax on our royalty lands in 2009 includes $1.3 million ($0.48 per boe) of freehold mineral tax recovered from certain lessees.

ROYALTY EXPENSE AND MINERAL TAX (1)

($000s, except as noted)	2010	2009	2008
Working interest			
Crown royalties	2,583	2,018	4,488
Third party royalties (2)	1,065	875	1,145
Mineral tax	250	489	445
Working interest	3,898	3,382	6,078
Per boe ($)	5.23	4.30	7.36
Royalty interest			
Crown royalties	-	-	-
Third party royalties (2)	-	-	-
Mineral tax	194	(649)	538
Royalty interest	194	(649)	538
Per boe ($)	0.10	(0.35)	0.27
Total	4,092	2,733	6,616
Per boe ($)	1.47	1.03	2.32
As a percentage of gross revenue	3%	2%	3%

(1) Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.
(2) Third party royalties include mineral title and gross overriding royalty payments to parties other than the Crown.

Operating Expenses

Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas, and NGL production. Overhead recoveries associated with operated properties are included in operating costs and accounted for as a reduction to general and administrative (G&A) expenses. A percentage of operating costs is fixed and, as such, per boe operating costs are highly variable to production volumes. Operating expenses on our working interest properties were 5% higher than last year (on a working interest boe basis), largely due to the effect of fixed costs on declining production at Hayter. Included in operating expenses for 2009 was a one-time adjustment of approximately $800,000 ($1.01 per working interest boe) for expenses incurred on certain working interest properties from 2005 to 2008 ($0.30 per boe on a total production basis).

OPERATING EXPENSES

($000s, except as noted)	2010	2009	2008
Working interest	11,569	11,655	11,299
Per boe ($)	15.52	14.82	13.67
Royalty interest (1)	-	-	-
Per boe ($)	-	-	-
Total operating expenses	11,569	11,655	11,299
Per boe ($)	4.16	4.37	3.96
As a percentage of gross revenue	8%	10%	6%

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

General and Administrative Expenses

G&A expenses include direct costs and reimbursement of the G&A expenses incurred by the Manager on our behalf (see Related Party Transactions). As we are now taking a more active role in our capital projects, particularly in Southeast Saskatchewan, we have capitalized more of our G&A expenses.

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. Higher G&A expenses in 2010 relate to one-time costs associated with the transition to International Financial Reporting Standards (IFRS) and our Reorganization. Expenses associated with the Reorganization (including consolidation of internal databases to enhance efficiency) are anticipated to be approximately $2.4 million, about half of which were incurred in 2010.

GENERAL AND ADMINISTRATIVE EXPENSES

($000s, except as noted)	2010	2009	2008
General and administrative expenses	7,408	7,303	6,877
Reorganization costs	1,073	-	-
Gross general and administrative expenses	8,481	7,303	6,877
Less: capitalized and overhead recoveries	(678)	(69)	(87)
Net general and administrative expenses	7,803	7,234	6,790
Per boe ($)	2.81	2.71	2.38
As a percentage of gross revenue	6%	6%	3%

Management Fees

The Manager receives a management fee in shares. The issue of 7.9 million trust units from treasury in the fourth quarter of 2009 and approximately 1.5 million trust units related to the DRIP in 2010 resulted in pro-rata increases in the management fee, in accordance with the management agreement (see Shareholders' Capital).

MANAGEMENT FEES (PAID IN SHARES)

	2010	2009	2008
Trust units issued in payment of management fees	169,411	148,597	142,616
Ascribed value ($000s) (1)	3,016	2,018	2,482
Per boe ($)	1.09	0.76	0.87
As a percentage of gross revenue	2%	2%	1%
As a percentage of distributions	3%	3%	2%

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

Share Based and Other Compensation

Manager's Long-Term Incentive Plan

We are responsible for funding a portion of the long-term incentive compensation plan for employees of the Manager (the Manager's LTIP). After a three-year vesting period, participants receive cash compensation in relation to the value of a specified number of notional rights. Dividends declared during the vesting period are assumed to be reinvested in notional rights on the dividend payment date. The LTIP liability is estimated at the end of each quarter based on the quarter-end share price and performance factors; the related compensation charges are recognized over the vesting period. Non-cash charges were higher in 2010 because of a higher period end share price which increased the plan's value. The 2006 LTIP grants vested in 2009 and $81,000 of share based compensation was paid out. The 2007 LTIP grants vested in 2010 and $1.5 million of share based compensation was paid out. A current liability of $2.3 million at December 31, 2010, relates to the 2008 LTIP grant, which vested in January 2011 and was paid out in February 2011.

Deferred Share Unit Plan

Fully-vested deferred share units (DSUs) (previously deferred trust units) are granted annually in the first quarter to non-management directors and are redeemable for an equal number of shares (less tax withholdings) any time after the director's retirement. Dividends declared prior to redemption are assumed to be reinvested in notional share units on the dividend payment date (see Shareholders' Capital).

Retirement Benefit Plan

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

SHARE BASED AND OTHER COMPENSATION

($000s, except as noted)	2010	2009	2008
Gross Manager's LTIP	3,919	2,862	(203)
Less: capitalized portion	(392)	-	-
Net Manager's LTIP	3,527	2,862	(203)
Deferred share unit plan	325	352	300
Retirement benefit	58	504	-
Share based and other compensation	3,910	3,718	97
Per boe ($)	1.41	1.40	0.03
As a percentage of gross revenue	3%	3%	0%

Interest Expenses

In 2010, interest and financing expense declined due to reduced debt levels. The average effective interest rate on advances under our credit facilities during 2010 was 3.1% (2009 – 2.4%).

INTEREST AND FINANCING

($000s, except as noted)	2010	2009	2008
Interest on operating line or other	2	-	31
Interest on long-term debt	3,599	4,678	7,008
Interest and financing	3,601	4,678	7,039
Per boe ($)	1.30	1.76	2.46
As a percentage of gross revenue	3%	4%	3%

Depletion, 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 Accounting Policies and Critical Estimates). Reserves are independently evaluated at year-end. For the first three quarters of 2010, the estimate of proved reserves was based on the independent evaluation dated December 31, 2009, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2010.

Our ceiling test calculation, performed at December 31, 2010, 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 quality, transportation, and contract differences.

DEPLETION, DEPRECIATION AND ACCRETION EXPENSES

($000s, except as noted)	2010	2009	2008
Depletion and depreciation	67,395	63,060	67,948
Accretion of asset retirement obligation	427	333	384
Total depletion, depreciation and accretion expenses	67,822	63,393	68,332
Per boe ($)	24.40	23.79	23.92
As a percentage of gross revenue	49%	53%	33%

Taxes

Income and Capital Taxes

Until December 31, 2010, Freehold was a taxable trust under the *Income Tax Act* (Canada). We distributed substantially all of our taxable income to unitholders. By doing so, exposure to current tax at the trust level was eliminated. As a corporation, Freehold is subject to corporate taxation. We currently have $235 million in tax pools available to shelter income from cash taxes. As an owner of primarily royalty interests, our ability to generate additional tax pools to shelter taxable income is limited. We do not expect to pay corporate income tax on income earned in 2011; however, starting in 2012, we expect to be cash taxable at a rate of 15% to 20%, which may reduce the amount available for dividends.

Capital taxes consist primarily of the Saskatchewan Capital Tax applied to both taxable capital and gross revenues in that province.

INCOME AND CAPITAL TAXES

($000s)	2010	2009	2008
Provincial capital tax	276	255	398
Current income tax	-	-	-
Total	276	255	398

Tax Pools

We are entitled to claim certain tax deductions available to all owners of oil and gas properties. For Freehold the principal deductions is Canadian Oil and Gas Property Expense. Freehold's tax pools are relatively modest as we have low capital expenditure requirements due to the nature of our royalty interests. The tax pools below are deductible at various rates.

TAX POOLS (1)

($000s)	2010	2009	2008
Canadian oil and gas property expense	195,932	179,058	188,957
Canadian development expense	23,980	18,967	16,154
Canadian exploration expense	370	380	276
Capital cost allowance	11,434	11,507	10,887
Trust unit issue costs	2,962	3,950	2,214
Total	234,678	213,862	218,488

(1) These amounts, subject to review by Canada Revenue Agency, represent Freehold's direct tax pools as well as the tax pools of our subsidiaries.

Future Income Taxes

The future income tax liability on our Consolidated Balance Sheets represents the net difference between tax values and accounting values (referred to as temporary differences) effected at substantively enacted tax rates expected to apply when the differences reverse. For the year ended December 31, 2010, the future income tax recovery was calculated on a corporate basis. For the year ended December 31, 2009, the future income tax recovery was calculated on the basis of a publicly traded income trust. At December 31, 2010, we had a future income tax liability of $34.1 million (December 31, 2009 – $36.1 million). In 2010, we recorded a non-cash recovery of $2.1 million (2009 - $5.3 million).

On a consolidated basis, Freehold's carrying value of its petroleum and natural gas interests exceeded the amount available for tax purposes by $145 million at December 31, 2010 (2009 - $176 million).

Liquidity and Capital Resources

We define capital as long-term debt, shareholders' equity, and working capital. We manage our capital structure taking into account operating activities, debt levels, debt covenants, capital expenditures, reclamation fund obligations, and dividend levels. We also consider changes in economic conditions and commodity prices as well as the risk characteristics of our assets. We have a depleting asset base, and ongoing development activities and acquisitions are necessary to replace production and extend reserve life. From time to time, we may issue shares or adjust capital spending to manage current and projected debt levels.

Operating Activities

The following table reconciles funds generated from operations to its nearest measure prescribed by Canadian GAAP.

OPERATING ACTIVITIES

($000s, except as noted)	2010	2009	2008
Cash provided by operating activities	110,693	95,659	179,252
Decrease in non-cash working capital	(3,722)	(574)	(7,970)
Funds generated from operations	106,971	95,085	171,282
Per share ($)	1.83	1.90	3.47

Financing Activities

We have a $195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which $65 million was drawn at December 31, 2010. In addition, we have available a $15 million extendible revolving operating facility.

The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice. The facilities are extendible annually with the latest review completed in May 2010. Freehold's borrowing base is dependent on the lenders' annual review and interpretation of Freehold's reserves and future commodity prices, with the next renewal to occur by May 2011. In the event that the lenders do not consent to an extension, the revolving credit facility would revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period, which is May 2011. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees.

Net proceeds from our equity issue in December 2009 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. In early 2010, we drew on our credit facilities to fund a $39 million royalty acquisition.

DEBT ANALYSIS

($000s)	2010	2009	2008
Long-term debt	65,000	45,000	140,000
Short-term debt (operating line)	-	-	-
Total debt	65,000	45,000	140,000
Working capital	6,479	3,082	20,055
Net debt obligations	71,479	48,082	160,055

We are bound by covenants on our credit facilities and we monitor these monthly to ensure compliance. Under our credit facility, we are restricted from declaring dividends if we are or would be in default under the credit facility or if our borrowings thereunder exceed our borrowing base, currently set at $210 million. As at December 31, 2010, we were in compliance with all such covenants.

FINANCIAL LEVERAGE AND COVERAGE RATIOS

	2010	2009	2008
Net debt to trailing funds generated from operations (times)	0.7	0.5	0.9
Net debt to distributions (times)	0.7	0.7	1.1
Distributions to interest expense (times)	27.2	15.1	20.4
Net debt to net debt plus equity (%)	21	14	42

We retain working capital primarily to fund capital expenditures or acquisitions and reduce bank indebtedness. The following table shows the changes in working capital during the past four quarters. In the oil and gas industry, accounts receivable from industry partners are typically settled in the following month. However, due to administrative issues, payments to royalty owners are often delayed longer. Therefore, working capital can fluctuate significantly due to volume and price changes at each period end.

COMPONENTS OF WORKING CAPITAL

($000s)	Dec. 31, 2010	Sep. 30 2010	Jun. 30 2010	Mar. 31 2010	Dec. 31 2009
Cash	409	438	779	152	432
Accounts receivable	22,631	19,365	20,729	24,244	24,056
Current assets	23,040	19,803	21,508	24,396	24,488
Distributions payable	(8,286)	(8,229)	(8,167)	(8,110)	(8,050)
Current portion of share based and other compensation	(2,473)	(1,944)	(1,867)	(1,932)	(1,643)
Accounts payable and accrued liabilities	(18,760)	(15,749)	(16,414)	(16,460)	(17,877)
Current liabilities	(29,519)	(25,922)	(26,448)	(26,502)	(27,570)
Working capital (1)	(6,479)	(6,119)	(4,940)	(2,106)	(3,082)

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

Commitments

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. If our lenders decide not to extend our credit facilities, we have a contractual obligation to make principal repayments on our long-term debt. Equal quarterly payments would be required in 2012 and 2013 based on the principal outstanding at the time the current agreement expires, which is May 2011. As per the terms of the agreement, the first quarterly payment would commence on January 1, 2012.

Shareholders' Capital

On October 26, 2009, our Board approved the monthly issuance of shares from treasury for the DRIP. Previously, additional shares issued in relation to the DRIP were purchased through the facilities of the Toronto Stock Exchange at prevailing market prices. In 2010, Freehold issued 1,508,958 shares (2009 – 260,740) related to the DRIP. The ascribed value of $25.7 million (2009 – $3.9 million) was based on the weighted average closing price for the 10 trading days preceding each payment date.

CN Pension Trust Funds, which owns approximately 25% of our shares, began participating in the DRIP, effective with the November 15, 2009 payment.

DISTRIBUTIONS PAID (1)

($000s)	2010	2009	2008
Distributions paid in cash	72,184	88,200	121,471
Distributions paid in shares	25,695	3,906	-
Total distributions paid	97,879	92,106	121,471

(1) Distributions paid during the period were paid on the 15th day of the month following the record date.

On December 10, 2009, we 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 underwriter's fees, were $4.9 million, resulting in net proceeds of $110.5 million.

As at December 31, 2010, there were 73,750 deferred share units (DSUs) outstanding (2009 – 53,070). During 2010, 13,916 DSUs were granted and no DSUs were redeemed. On January 1, 2011, the Board granted 10,248 DSUs to eligible directors as part of their annual compensation. Each eligible director received 1,464 DSUs and the Chair of the Board received 2,928 DSUs (see Share Based and Other Compensation). As at March 2, 2011, there were 85,003 DSUs outstanding.

During 2010, Freehold issued 169,411 shares (2009 – 148,547 shares) for payment of the management fee (see Related Party Transactions).

On December 31, 2010, pursuant to the Reorganization all outstanding trust units were exchanged for common shares on the basis of one common share for each trust unit held. As at December 31, 2010, there were 59,181,312 shares outstanding and as at March 2, 2011, there were 59,392,817 shares outstanding. Pursuant to the Reorganization, Freehold's deficit on December 31, 2010, was eliminated by reducing shareholders' capital by $448.6 million.

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta) (ABCA). Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2010, our legal stated capital was approximately $250 million. As a corporation, our dividend policy will be similar to our distribution policy as a trust. Dividends will continue to be paid monthly, with the Board reviewing the dividend policy quarterly.

SHARES OUTSTANDING (1)

	2010	2009	2008
Weighted average			
Basic	58,334,117	49,999,617	49,370,878
Diluted	58,389,088	50,053,435	49,412,670
At December 31	59,181,312	57,502,943	49,459,429

(1) Prior to conversion to a corporation on December 31, 2010, Freehold had trust units outstanding instead of shares.

Historical Distributions

2010 DISTRIBUTIONS DECLARED

Record Date	Payment Date	Dividend ($ per share)
January 31, 2010	February 15, 2010	0.14
February 28, 2010	March 15, 2010	0.14
March 31, 2010	April 15, 2010	0.14
April 30, 2010	May 15, 2010	0.14
May 31, 2010	June 15, 2010	0.14
June 30, 2010	July 15, 2010	0.14
July 31, 2010	August 15, 2010	0.14
August 31, 2010	September 15, 2010	0.14
September 30, 2010	October 15, 2010	0.14
October 31, 2010	November 15, 2010	0.14
November 30, 2010	December 15, 2010	0.14
December 31, 2010	January 17, 2011	0.14
Total		1.68

Distributions declared in 2010 totalled $98.1 million ($1.68 per trust unit). For Canadian tax purposes, distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the trust units held. In 2010, 72% of distributions declared were taxable as income, unless held in a registered plan. The remaining 28% of distributions were classified as a return of capital. For a more detailed breakdown, please visit our website at www.freeholdroyalties.com.

In 2011, Freehold began paying dividends to its shareholders. Dividends are taxed differently from distributions of the Trust in that dividends do not comprise a return of capital and thus are fully taxable.

From inception to December 31, 2010, Freehold distributed $893.0 million ($22.21 per share) to shareholders.

ACCUMULATED DISTRIBUTIONS

	2010	2009	2008
Distributions declared ($000s)			
Accumulated, beginning of year	794,898	724,418	580,669
Accumulated, end of year	893,013	794,898	724,418
Distributions per share ($) (1)			
Accumulated, beginning of year	20.53	19.13	16.22
Accumulated, end of year	22.21	20.53	19.13

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

Investing Activities

Acquisitions

We continue to pursue opportunities to augment our production and reserves, primarily targeting royalty interests. We maintain a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future shareholders. Our acquisition criteria include the following factors:

- quality assets;
- attractive returns;
- reasonable assumptions;
- high operating netbacks; and
- long economic life.

Over the past three years, we have completed the following acquisitions, all of which were funded through our credit facilities:

- On February 17, 2010, we acquired royalty interests in Alberta, Saskatchewan, and British Columbia, for $39 million.
- On December 21, 2009, we acquired royalty interests in Alberta for $10 million.
- On July 7, 2008, we acquired royalty and minor working interests in Alberta for $8.5 million.

PROPERTY AND ROYALTY ACQUISITIONS

($000s)	2010	2009	2008
Purchase price	40,500	10,700	8,475
Interest expense	350	112	-
Evaluation and legal costs	54	47	-
Purchase price adjustments (1)	(2,747)	(849)	-
Prior years acquisition adjustments	443	(471)	(782)
Additions to petroleum and natural gas interests	38,600	9,539	7,693

(1) Net revenue from effective date to closing.

Capital Expenditures

As we do not incur development expenditures on our royalty lands, our capital requirements are modest, relative to most of our peers. In 2010, development expenditures of $18.1 million amounted to 17% of funds generated from operations.

We expect to fund capital expenditures from cash provided by operating activities. However, we will continue to fund acquisitions and growth through additional debt and equity. In the upstream oil and gas sector, because of the nature of reserve reporting, natural reservoir depletion, and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Therefore, maintenance capital is not disclosed separately from development capital spending.

CAPITAL EXPENDITURES

($000s, except as noted)	2010	2009	2008
Development drilling and other	14,718	11,702	10,349
Plant and facilities	3,336	3,789	2,643
Total capital expenditures	18,054	15,491	12,992
As a percentage of funds generated from operations	17%	16%	8%

Reclamation Fund

We have no reclamation responsibilities on our royalty assets, as these are the responsibility of the working interest owners.

We are liable for our share of ongoing environmental obligations and the ultimate reclamation of our working interest properties upon abandonment. At December 31, 2010, the undiscounted value of future environmental and reclamation obligations for the working interest properties was estimated to be $22.6 million. In 1996, we established a reclamation fund consisting of cash, invested in an interest-bearing account, funded by quarterly cash payments. All liabilities settled to the end of 2010 were paid from the reclamation fund. At December 31, 2010, the fund had a balance of $2.7 million. Subsequent to year-end, we discontinued the use of the reclamation fund. Ongoing environmental obligations will be funded from funds generated from operations.

RECLAMATION FUND SUMMARY

($000s)	Cumulative Since Inception	2010	2009	2008
Reclamation fund, beginning balance	-	2,261	1,827	1,788
Reclamation fund contributions	5,510	810	607	641
Expenditures on reclamation	(2,785)	(346)	(173)	(602)
Reclamation fund, ending balance	2,725	2,725	2,261	1,827

Business Risks and Mitigating Strategies

The operations are subject to the same industry risks and conditions faced by all oil and gas companies. The most significant of these include the following:

- fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and natural gas;
- variations in currency exchange rates;
- imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. Our reserves will deplete over time through continued production and we and our industry partners and royalty payors may not be able to replace these reserves on an economic basis;
- industry activity levels and intense competition for land, goods and services, and qualified personnel;
- stock market volatility and the ability to access sufficient capital from internal and external sources;
- risk associated with volatility in global financial markets;
- risk associated with the renegotiation of our credit facility;
- operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- changes in government regulations, taxation, and royalties; and
- safety and environmental risks.

For a more detailed description of risk factors, please see our AIF.

We employ the following strategies to mitigate these risks:

- Our diversified revenue stream limits the size of any one property with respect to our total assets.
- We are not liable for abandonment and reclamation costs on our royalty lands.
- Due to our high percentage of royalty lands, we have one of the lowest all-in cost structures of our peer group. In addition, we maintain a focus on controlling direct costs to maximize profitability.
- We maintain an aggressive auditing program to collect royalties on production from our lands in accordance with the terms of the various leases and agreements. During 2010, our audit staff issued audit exception queries amounting to $4.8 million, bringing the total amount of audit exception queries since 1997 to $44.2 million, of which we have successfully recovered $35.1 million.
- We adhere to strict investment criteria for acquisitions, seeking royalty and working interest properties that have high netbacks, long reserve life, low risk development potential, and product diversification.
- We market our products to a diverse range of buyers. Currently, we do not have any commodity price, exchange rate, or interest rate hedging programs in place.
- We employ a qualified Manager that has many years of experience and knowledge in managing our assets.
- We maintain levels of liability insurance that meet or exceed industry standards.
- We employ a conservative approach to debt management. As circumstances warrant, we allocate a portion of funds generated from operations to debt repayment.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue. The most significant of these regulations are summarized below, and additional information about environmental regulation can be found in our AIF.

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

Federal Climate Change Regulation

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the Action Plan) to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the Updated Action Plan). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be: (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose greenhouse gas emissions standards for fossil fuel-fired power plants by July 2011 and for refineries by December 2011.

Provincial Climate Change Regulation

The majority of Freehold's land holdings and production are in the provinces of Alberta and Saskatchewan.

On December 4, 2003, Alberta enacted the Climate Change and Emissions Management Act (the CCEMA), amending it through the Climate Change and Emissions Management Amendment Act which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. The CCEMA contains similar compliance mechanisms as the Updated Action Plan. On December 2, 2010, the Government of Alberta passed the Carbon Capture and Storage Statutes Amendment Act, 2010, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

On May 11, 2009, the Government of Saskatchewan announced The Management and Reduction of Greenhouse Gases Act (the MRGGA) to regulate greenhouse gas emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

Controls and Accounting Matters

In compliance with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings (NI 52-109), Freehold has filed certificates signed by our Chief Executive Officer (CEO) and Chief Financial Officer (CFO) that, among other things, deal with the matter of disclosure controls and procedures and internal control over financial reporting. While we believe that our disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance, we do not expect that the controls will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

Disclosure Controls

Disclosure controls and procedures are controls and other procedures that are designed to provide reasonable assurance that information required to be disclosed in regulatory filings is recorded, processed, summarized, and reported within the periods specified. They include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure.

Management has evaluated the effectiveness of Freehold's disclosure controls and procedures as of March 2, 2011. This evaluation was performed under the supervision of, and with the participation of the CEO and the CFO. It took into consideration Freehold's Disclosure, Insider Trading, Code of Business Conduct and Conflict of Interest, and Whistleblower policies, as well as the functioning of the Manager, the officers, the Board and Board Committees. In addition, the evaluation covered the processes, systems and capabilities relating to regulatory filings, public disclosures, and the identification and communication of material information. Based on this evaluation, management has concluded that Freehold's disclosure controls are effective in ensuring that material information is made known to management on a timely basis.

Internal Control Over Financial Reporting

Internal control over financial reporting is a process designed to provide reasonable assurance about the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP. The process includes policies and procedures to:

- maintain records that accurately and fairly reflect transactions and dispositions of assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements and that receipts and expenditures are being made with proper authorization; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized transactions that could have a material effect on the financial statements.

Our CEO and CFO are responsible for establishing and maintaining internal control over financial reporting (ICFR). They have caused ICFR to be designed under their supervision to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP. The control framework used to design ICFR is the Internal Control – Integrated Framework (COSO Framework) published by The Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Under the supervision of the CEO and CFO, Freehold conducted an evaluation of the effectiveness of its ICFR as at December 31, 2010, as structured within the COSO Framework. Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2010, our ICFR provides reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. There were no changes in our ICFR during 2010 that materially affected Freehold's ICFR.

Changes in Accounting Policies, Including Initial Adoption, and New Accounting Standards

International Financial Reporting Standards (IFRS)

In January 2006, the Canadian Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under IFRS, which will replace Canadian GAAP. In October 2009, the AcSB confirmed January 1, 2011 as the changeover date to commence reporting under IFRS. This adoption date will require the restatement, for comparative purposes, of amounts reported by Freehold for the year ended December 31, 2010, including our opening balance sheet as at January 1, 2010.

The conversion project is being led by internal staff, assisted by an external advisor, and we involve our external auditors in the process. Our transition plan addresses resources required, training, analysis of accounting standard differences, accounting policy determination, evaluation of information system requirements and an impact assessment on operations, internal controls over financial reporting and disclosures.

We have made significant progress in many of the areas, including assessing the impact of accounting policy choices under IFRS, educating the Board, and training employees. We have also made preliminary conclusions under IFRS 1, *First-Time Adoption of International Financial Reporting Standards*, which provides certain exemptions from full retroactive application. We have made preliminary policy choices, and the major ones were presented to our audit committee. Based on our preliminary policy choices, we continue to work on our January 1, 2010 opening balance sheet, with ongoing review by our audit committee and external auditors.

Some of the major considerations, decisions and effects with respect to accounting policy choices are identified below. However, some of our decisions may change, as IFRS continues to evolve as we approach our 2011 financial reporting deadlines.

- For property, plant and equipment (PP&E), we have made decisions under IAS 16 regarding asset valuation, cash generating units (CGUs), and depletion and depreciation. All of Freehold's petroleum and natural gas interests will be classified as PP&E assets with the exception of exploration and evaluation (E&E) assets. Under IFRS 1, we will use the option of recording opening values at their deemed cost, which is the net book value under Canadian GAAP at January 1, 2010, rather than retrospectively applying the requirements of IAS 16. We will allocate these values based on the reserve value at that point in time. We have chosen to record depletion and depreciation at the CGU level using proved plus probable reserves, rather than proved reserves. Consequently, depletion expense and accumulated depletion will be lower under IFRS than under Canadian GAAP.
- Freehold has limited E&E assets, currently in the form of undeveloped land. The original valuation of these assets will be affected by IFRS 1, whereby we will use an option to use their deemed cost which is the net book value under Canadian GAAP at January 1, 2010. We have determined a capitalization policy for determining when to treat these assets under IAS16 rather than under IFRS 6.
- Impairment testing for Freehold's PP&E and E&E assets will occur at a CGU level using fair values based on independent evaluations. For PP&E, the independent evaluations will be based on proved plus probable reserves. 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. Freehold's preliminary calculations show no impairments at January 1, 2010 under IFRS.
- For our asset retirement obligations, we will use the option under IFRS 1 to revalue our obligation at January 1, 2010, using the appropriate discount rate at that date, rather than retrospectively revaluing each year as required under IAS 37. A major difference between current Canadian GAAP and IFRS is the discount rate used to value expected cash flows. Canadian GAAP uses a credit-adjusted risk free rate, while IFRS may be interpreted as requiring use of a risk free rate. Within the oil and natural gas industry, there has been debate on whether a risk component should be applied. Freehold has made a preliminary decision to use a risk free rate, but we continue to monitor this matter. If a risk free rate is used, our opening balance sheet asset retirement liability will increase under IFRS compared to Canadian GAAP by approximately $1 million.
- For share-based payments, we do not expect to apply IFRS 2 retrospectively on equity settled instruments fully vested or cash settled payments transacted by January 1, 2010. Freehold will be removing the deferred asset from the balance sheet, which is $2 million at the opening balance sheet date, and the liability will be reduced by a similar amount.
- For the purpose of our January 1, 2010 opening balance sheet, our assessment is that our trust units are equity, which would not require a change from the current accounting.

- Under IFRS, the conceptual foundation for future income tax is similar to Canadian GAAP, with both using the "liability method". Tax rates are applied to temporary differences in carrying amounts of assets and liabilities compared to the value attributed for tax purposes. IFRS requires a "rate applicable to undistributed profits" be used, which for a trust is the highest marginal individual rate. This will have the effect of originally decreasing the liability on the opening balance sheet by approximately $3 million, with an offset to retained earnings. However, the charge subsequently reverses upon Freehold's conversion to a corporation.
- We plan to apply an IFRS 1 optional exemption regarding business combinations wherein Freehold will not retrospectively restate any business combinations recorded under Canadian GAAP prior to January 1, 2010.

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

Because Freehold has a unique business model with unique assets (predominately royalty interest properties), the changes required will be less significant than for a typical oil and natural gas operation.

Prior to the release of our first IFRS interim financial statements we will focus on preparing 2010 quarterly financial statements under IFRS and drafting note disclosures for review by our audit committee. Note disclosure will be significantly more extensive than under Canadian GAAP.

Even though we have made many preliminary decisions based on information known to date, the assessments of differences between IFRS and Canadian GAAP have not yet been finalized or approved by Freehold's Board of Directors. We continue to monitor developments and caution that certain items may change based on new facts and circumstances.

Accounting Policies and Critical Estimates

Our financial statements are prepared within a framework of Canadian GAAP selected by management and approved by our Board. 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, oil and gas revenue accruals, asset retirement obligations, and future income taxes. 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. Actual results could differ from the estimates, as additional information becomes known.

An estimate is considered a critical accounting estimate if it requires management to make assumptions about matters that are highly uncertain, and if different estimates that could have been used would have a material impact. We continually evaluate the estimates and assumptions. In the normal course, changes are made to assumptions underlying all critical accounting estimates to reflect current economic conditions, and updating of historical information is used to develop the assumptions. Except as discussed in this MD&A, we are not aware of trends, commitments, events, or uncertainties that are expected to materially affect the methodology or assumptions associated with the critical accounting estimates.

Reserve Estimates, Depletion and Ceiling Test

The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2010. Reserve estimates are updated once a year (as at December 31) and when a significant acquisition is completed. The reserve and recovery information provided are only estimates. The actual production and ultimate reserves may be greater than or less than the estimates and the differences may be material.

We follow the full cost method of accounting for petroleum and natural gas interests. Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in the depletion rate. As at December 31, 2010, the depletion calculation included $0.8 million for estimated future development costs associated with proved undeveloped reserves and excluded $22.5 million for the lower of cost and estimated value of unproved lands.

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties. The ceiling test estimates were reviewed at year-end to ensure that they are reasonable and supportable in light of current economic conditions. The ceiling test, performed as at December 31, 2010, indicated that the undiscounted future net revenues from proved reserves exceed the net book value of the properties. Accordingly, no write down of oil and gas properties was required.

Accruals

Freehold follows the accrual method of accounting, making estimates in its financial and operating results. This may include estimates of revenues, royalties, production and other expenses and capital items related to the period being reported, for which actual results have not yet been received. We expect that these accrual estimates will be revised, upwards or downwards, based on the receipt of actual results. We have no operational control over our royalty lands, and we primarily hold small interests in several thousand wells. Thus, obtaining timely production data from the well operators is extremely difficult. As a result, we use government reporting databases and past production receipts to estimate revenue accruals.

Asset Retirement Obligation

We recognize the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on the unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

We have no asset retirement obligation on our royalty interest properties. Freehold's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The undiscounted value of Freehold's total asset retirement obligation is estimated to be $22.6 million. Payments to settle the obligations are expected to occur continuously over the next 60 years, with the majority of obligations being settled between 10 to 30 years away. A credit adjusted risk free rate ranging from 5% to 6% and an inflation rate of 1.5% (2009 – 2.0%) were used to calculate the fair value.

A reclamation fund, consisting of cash invested in an interest-bearing account, was established and funded by quarterly cash payments. All liabilities settled during the periods were paid from the reclamation fund. Subsequent to December 31, 2010, Freehold discontinued the use of the reclamation fund.

In determining our asset retirement obligation, we are required to make a significant number of estimates with respect to activities that will occur in many years to come. In arriving at the recorded amount of the asset retirement obligation, numerous assumptions are made with respect to ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligation also results in an increase to the carrying cost of capital assets. The obligation accretes to a higher amount with the passage of time as it is determined using discounted present values. A change in any one of the assumptions could affect the estimated future obligation and in return, net income. It is difficult to determine the impact of a change in any one of our assumptions. As a result, a reasonable sensitivity analysis cannot be performed.

Future Income Taxes

We follow the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of future income tax may be greater than or less than the estimates and the differences may be material.

Share Based and Other Compensation

We fund Freehold's proportionate share of the costs associated with a long-term incentive compensation plan for employees of Rife Resources, the Manager of Freehold (the Manager's LTIP). The Manager's LTIP uses a combination of the value of phantom Rife shares and Freehold's common shares as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Dividends paid during the vesting period are assumed to be reinvested in notional rights on the dividend payment date. Since participants in the Manager's LTIP receive a cash payment on a fixed vesting date, a liability is determined based on the fair value of the rights at each period end. The valuation incorporates the period end share price, the number of rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with the portion of the liability not yet expensed treated as a deferred asset. Freehold has not incorporated an estimated forfeiture rate for rights that will not vest; rather, Freehold accounts for actual forfeitures as they occur.

A deferred share unit plan (previously the deferred trust unit plan) was established for the non-management directors of Freehold whereby fully-vested deferred share units are granted annually. Under this plan, dividends to shareholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional share units on the dividend payment date. Compensation expense is recognized at the market value of Freehold's common shares at the time of grant or dividend, with a corresponding increase to contributed surplus. Upon redemption of the deferred share units for Freehold's common shares, the amount previously recognized in contributed surplus is recorded as an increase to shareholders' capital.

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

Related Party Transactions

Freehold does not have any employees. The Manager of Freehold 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), which in turn is a shareholder of Freehold. The Manager recovers its general and administrative costs and a portion of its long-term incentive plan costs and retirement benefit costs, and receives a quarterly management fee paid in shares.

The Manager provides certain services for a fee based on a specified number of shares per quarter, pursuant to the amended and restated management agreement which has a term of three years and will be renewed in November 2013 unless terminated. During 2010, the management fee paid was 169,411 trust units with an ascribed value of $3.0 million (2009 – 148,597 trust units with an ascribed value of $2.0 million).

For the year ended December 31, 2010, the Manager charged Freehold $5.7 million (2009 – $5.7 million) in general and administrative 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 both parties.

Contingency

In May 2009, a statement of claim was filed against Freehold for $9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, we have assessed the claim, believe it has no merit, and intend to aggressively defend against the claim. The claim's outcome is not determinable and therefore, no liability has been recorded in the financial statements.

Forward-Looking Statements

Certain statements contained in this MD&A constitute forward-looking statements. These statements relate to future events or our expectations of future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "forecast", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions (including the negatives thereof). These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and, as such, forward-looking statements included in this MD&A should not be unduly relied upon. These forward-looking statements are provided to allow readers to better understand our business and prospects.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- our outlook for commodity prices including supply and demand factors relating to crude oil, foreign exchange rates, heavy oil, heavy oil price differentials, and natural gas;
- changing economic conditions;
- projections of market prices and costs and the related sensitivities to net income;
- industry drilling levels and development activity on our royalty lands;
- expectations regarding the ability to raise capital (including DRIP participation and available credit) and add reserves through acquisitions and development;
- estimated capital expenditures and the timing thereof;
- long-term debt at year end;
- average production and contribution from royalty lands;
- key operating assumptions;
- acquisition opportunities;
- future income tax;
- the expected impact of international financial reporting standards on our reported results;
- our dividend policy payout ratio; and
- our tax pools and the expected tax horizon; and
- treatment under governmental regulatory regimes and tax laws

Our actual results could differ materially from those anticipated in these forward-looking statements because of many factors, the most significant of which are as follows:

- volatility in market prices for oil and natural gas;
- currency fluctuations;
- changes in income tax laws or changes in tax laws, regulations, royalties, or incentive programs relating to the oil and gas industry;
- uncertainties or imprecision associated with estimating oil and natural gas reserves;
- stock market volatility and our ability to access sufficient capital from internal and external sources;
- a significant or prolonged downturn in general economic conditions or industry activity;
- incorrect assessments of the value of acquisitions;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling, and processing problems;
- environmental risks and liabilities inherent in oil and natural gas operations; and
- other factors discussed under Business Risks and Mitigating Strategies in this MD&A, and under Risk Factors and elsewhere in our AIF.

Readers are cautioned that the foregoing list of factors is not exhaustive.

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, the following:

- future oil and natural gas prices;
- future capital expenditure levels;
- future production levels;
- future exchange rates;
- future tax rates;
- expected participation in our DRIP;
- the cost of developing and expanding our assets;
- our ability and the ability of our industry partners and royalty payors to obtain equipment in a timely manner to carry out development activities;
- our ability to market our oil and natural gas successfully to current and new customers;
- the impact of increasing competition;
- our ability to obtain financing on acceptable terms; and
- our ability to add production and reserves through our development and acquisition activities.

The Outlook section sets forth our key operating assumptions with respect to the forward-looking statements contained in this MD&A.

The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement and speak only as of the date of this MD&A. 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.

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 Canadian 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 dividends. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP. The key difference between cash provided by operating activities and funds generated from operations is changes in non-cash working capital, which is affected by accounts receivable and 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 Consolidated Statements of Cash Flows. Funds generated from operations per share is calculated based on the weighted average number of shares outstanding consistent with the calculation of net income per share (see Liquidity and Capital Resources – Operating Activities).

Net debt to funds generated from operations is calculated as net debt (total debt adjusted for working capital) as a proportion of funds generated from operations for the previous 12 months (see Debt Analysis).

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

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, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation.

Management's Report

Management has prepared the accompanying consolidated financial statements of Freehold Royalties Ltd. in accordance with Canadian generally accepted accounting principles.

Management is responsible for the accuracy and integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and reliable accounting records are produced for financial reporting purposes.

External auditors, KPMG LLP, were appointed by the shareholders to perform an examination of the corporate and accounting records so as to express an opinion on the consolidated financial statements of Freehold Royalties Ltd. Their examination included tests and procedures considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the audit committee, all of whose members are independent directors of Freehold Royalties Ltd. The committee meets with management and the independent auditors to ensure that management's responsibilities are properly discharged.

William O. Ingram
President and Chief Executive Officer

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

March 2, 2011

Independent Auditors' Report

To the Shareholders of Freehold Royalties Ltd.

We have audited the accompanying consolidated financial statements of Freehold Royalties Ltd. (the "Company"), which comprise the consolidated balance sheets as at December 31, 2010 and 2009, the consolidated statements of income, comprehensive income and deficit, and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2010 and 2009, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 2, 2011

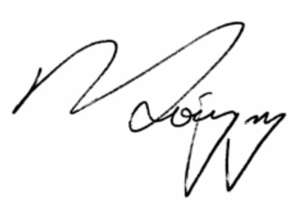
Freehold
ROYALTIES LTD.

CONSOLIDATED BALANCE SHEETS

($000s)		December 31 2010		December 31 2009
Assets				
Current assets:				
Cash	$	409	$	432
Accounts receivable		22,631		24,056
		23,040		24,488
Reclamation fund (note 6)		2,725		2,261
Deferred long-term compensation (note 9)		2,381		1,954
Petroleum and natural gas interests (note 3)		379,314		389,837
	$	407,460	$	418,540
Liabilities and Shareholders' Equity				
Current liabilities:				
Distributions payable	$	8,286	$	8,050
Accounts payable and accrued liabilities		18,760		17,877
Current portion of share based and other compensation payable (note 9)		2,473		1,643
		29,519		27,570
Asset retirement obligation (note 6)		7,067		7,160
Share based and other compensation payable (note 9)		5,629		3,702
Long-term debt (note 5)		65,000		45,000
Future income tax liability (note 10)		34,079		36,136
Shareholders' equity:				
Shareholders' capital (note 7)		265,082		684,979
Contributed surplus (note 9)		1,084		759
Deficit (note 7)		-		(386,766)
		266,166		298,972
	$	407,460	$	418,540

See accompanying notes to consolidated financial statements.

On behalf of the Board of Directors of Freehold Royalties Ltd.:



D. Nolan Blades
Director

Rodger A. Tourigny
Director

Freehold
ROYALTIES LTD.

CONSOLIDATED STATEMENTS OF INCOME, COMPREHENSIVE INCOME AND DEFICIT

($000s, except per share and weighted average data)	Year Ended December 31 2010	2009
Revenue:		
Royalty income and working interest sales	$ 138,155	$ 119,965
Royalty expense and mineral tax	(4,092)	(2,733)
	134,063	117,232
Other income/expense (note 11)	(1,850)	2,122
Expenses:		
Operating	11,569	11,655
General and administrative	7,803	7,234
Share based and other compensation (note 9)	3,910	3,718
Interest and financing	3,601	4,678
Depletion and depreciation	67,395	63,060
Accretion of asset retirement obligation (note 6)	427	333
Management fee (note 8)	3,016	2,018
	97,721	92,696
Income before taxes	34,492	26,658
Income and capital taxes:		
Income and capital taxes (note 10)	276	255
Future income tax reduction (note 10)	(2,057)	(5,338)
	(1,781)	(5,083)
Net income and comprehensive income	36,273	31,741
Deficit, beginning of year	(386,766)	(348,027)
Distributions declared	(98,115)	(70,480)
Elimination of deficit in accordance with the Reorganization (note 7)	448,608	-
Deficit, end of year	$ -	$ (386,766)
Net income per share, basic and diluted	$ 0.62	$ 0.63
Weighted average number of shares:		
Basic	58,334,117	49,999,617
Diluted	58,389,088	50,053,435

See accompanying notes to consolidated financial statements.

Freehold
ROYALTIES LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

($000s)	Year Ended December 31 2010	2009
Cash provided by (used in):		
Operating:		
Net income	$ 36,273	$ 31,741
Items not involving cash:		
Depletion and depreciation	67,395	63,060
Share based and other compensation	3,910	3,718
Future income tax reduction	(2,057)	(5,338)
Accretion of asset retirement obligation	427	333
Trust units issued in lieu of management fee	3,016	2,018
Expenditures on share based and other compensation	(1,647)	(274)
Expenditures on reclamation	(346)	(173)
	106,971	95,085
Changes in non-cash working capital (note 14)	3,722	574
	110,693	95,659
Financing:		
Issue of trust units, net of issue costs	-	110,486
Long-term debt	20,000	(95,000)
Distributions paid	(72,184)	(88,200)
	(52,184)	(72,714)
Investing:		
Property and royalty acquisitions	(38,600)	(9,539)
Capital expenditures	(18,054)	(15,491)
Change in reclamation fund	(464)	(434)
Changes in non-cash working capital (note 14)	(1,414)	2,414
	(58,532)	(23,050)
Decrease in cash	(23)	(105)
Cash, beginning of year	432	537
Cash, end of year	$ 409	$ 432

See accompanying notes to consolidated financial statements.

Notes to the Consolidated Financial Statements

Years ended December 31, 2010 and 2009

Basis of Presentation

Freehold Royalties Ltd. (Freehold) is a dividend paying corporation incorporated under the laws of the Province of Alberta and its primary focus is acquiring and managing oil and gas royalties. These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP).

Freehold Royalties Ltd. resulted from a reorganization effective December 31, 2010 pursuant to a Plan of Arrangement (the Reorganization) approved on December 10, 2010 at a special meeting of unitholders. The Reorganization involved Freehold Royalty Trust (the Trust), Freehold Royalties Ltd., Freehold Resources Ltd., Freehold Royalties Partnership (a general partnership previously named Petrovera Resources) and the Trust's unitholders, among others. As part of the Reorganization, the Trust was restructured from an open-ended investment trust to a dividend paying corporation. All outstanding trust units were exchanged for common shares on the basis of one common share for each trust unit held.

The Reorganization has been accounted for on a continuity-of-interest basis. Therefore, the consolidated financial statements for periods prior to the Reorganization reflect Freehold's financial position, results of operations and cash flows as if it had always carried on the business formerly carried on by the Trust. These consolidated financial statements include information with respect to the Trust prior to the Reorganization. In these and future financial statements Freehold will refer to common shares, shares, shareholders and dividends, which were formerly referred to as trust units, units, unitholders and distributions under the trust structure.

Pursuant to the Reorganization, shareholders' capital was reduced by $448.6 million, the amount necessary to eliminate the consolidated deficit of Freehold outstanding at the time of the Reorganization.

These consolidated financial statements include the accounts of Freehold Royalties Ltd. and its wholly-owned subsidiaries. All inter-entity transactions have been eliminated.

1. Significant Accounting Policies

(a) Petroleum and Natural Gas Interests

Freehold follows the full cost method of accounting. All costs of acquiring, exploring for and developing oil and gas and related reserves are capitalized. Such costs include land acquisition, geological and geophysical, carrying charges of unproved properties, costs of drilling both productive and non-productive wells, directly related administrative costs and asset retirement costs. Costs are reduced by proceeds from the sale of oil and gas properties. Gains and losses are not recognized upon disposition of oil and gas properties unless such a disposition would alter the rate of depletion by 20% or more.

(b) Ceiling Test

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties. The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(c) Depletion

Oil and gas interests and royalty interests, including the costs of production equipment, future capital costs associated with proved reserves, and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. Reserves are converted to equivalent units on the basis of relative energy content.

(d) Asset Retirement Obligation

Freehold recognizes the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on the unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

(e) Income and Other Taxes

Freehold follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

(f) Use of Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses during the reporting period. Actual results could differ as a result of using estimates.

The amounts recorded for depletion of petroleum and natural gas properties and asset retirement obligations and amounts used in ceiling test calculations, are based on estimates of petroleum and natural gas reserves and future costs to develop those reserves. By their nature, these estimates of reserves, costs, and related future cash flows are subject to uncertainty, and the impact on the financial statements of future periods could be material.

Freehold follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of future income tax may be greater than or less than the estimates and the differences may be material.

(g) Share Based and Other Compensation Plans

Freehold funds its proportionate share of the costs associated with a long-term incentive compensation plan for employees of Rife Resources, the Manager of Freehold (the Manager's LTIP). The Manager's LTIP uses a combination of the value of phantom Rife shares and Freehold's common shares as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Dividends paid during the vesting period are assumed to be reinvested in notional rights on the dividend payment date. Since participants in the Manager's LTIP receive a cash payment on a fixed vesting date, a liability is determined based on the fair value of the rights at each period end. The valuation incorporates the period end share price, the number of rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with the portion of the liability not yet expensed treated as a deferred asset. Freehold has not incorporated an estimated forfeiture rate for rights that will not vest; rather, Freehold accounts for actual forfeitures as they occur.

A deferred share unit plan (previously the deferred trust unit plan) was established for the non-management directors of Freehold whereby fully-vested deferred share units are granted annually. Under this plan, dividends to shareholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional share units on the dividend payment date. Compensation expense is recognized at the market value of Freehold's common shares at the time of grant or dividend, with a corresponding increase to contributed surplus. Upon redemption of the deferred share units for Freehold's common shares, the amount previously recognized in contributed surplus is recorded as an increase to shareholders' capital.

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

(h) Net Income Per Share

Basic shares outstanding are the weighted average number of shares outstanding for each period. Diluted shares outstanding are calculated using the treasury stock method, which assumes that any proceeds received from options with a market value in excess of option price would be used to buy back shares at the average market price for the period.

(i) Revenue Recognition

Revenue from the sale of crude oil, natural gas and natural gas liquids is recognized when title passes from Freehold, or the operator of Freehold's royalty properties, to its customers.

(j) Financial Instruments

All financial instruments, including all derivatives, are to be recognized on the balance sheet initially at fair value. Subsequent measurement of all financial assets and liabilities except those held-for-trading and available-for-sale are measured at amortized cost determined using the effective interest rate method. Held-for-trading financial assets are measured at fair value with changes in fair value recognized in earnings. Available for-sale financial assets are measured at fair value with changes in fair value recognized in comprehensive income and reclassified to earnings when derecognized or impaired.

Cash, reclamation fund, and short-term investments, if any, are held-for-trading investments, and the fair values approximate their carrying value due to their short-term nature. Accounts receivable are classified as loans and receivables, and accounts payable and accrued liabilities and long-term debt are classified as other financial liabilities. The fair values of accounts receivable and accounts payable and accrued liabilities approximate their carrying value due to the short-term nature of these instruments. Freehold has not designated any financial instruments as available-for-sale or held-to-maturity. Freehold did not identify any material embedded derivatives which required separate recognition and measurement.

CICA Handbook Section 3862, Financial Instruments – Disclosures, requires Freehold to include additional disclosure about fair value measurement for financial instruments and liquidity risk disclosures. A three level hierarchy that reflects the significance of the inputs used in making the fair value measurements is required. 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.

2. New Accounting Standards

International Financial Reporting Standards

In January 2006, the Canadian Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under International Financial Reporting Standards (IFRS), which will replace Canadian GAAP. In October 2010, the AcSB confirmed January 1, 2011 as the changeover date to commence reporting under IFRS.

3. Petroleum and Natural Gas Interests

($000s)		2010		2009
Petroleum and natural gas interests	$	959,848	$	902,976
Accumulated depletion and depreciation		(580,534)		(513,139)
Petroleum and natural gas interests, net	$	379,314	$	389,837

The depletion calculation included $0.8 million (2009 – $0.9 million) for estimated future development costs associated with proved undeveloped reserves and excluded $22.5 million (2009 – $27.6 million) for the lower of cost and market value of unproved lands.

For the year ended December 31, 2010, Freehold capitalized $0.6 million of administrative costs and $0.4 million of long-term incentive plan costs directly related to development activities. With minimal operated capital activity prior to 2010, only immaterial amounts were capitalized.

Freehold's ceiling test calculation, performed at December 31, 2010, resulted in no impairment loss. The future prices used by Freehold in estimating cash flows were based on forecasts by an independent qualified reserves evaluator, adjusted for Freehold's quality, transportation, and contract differences. The following table summarizes the benchmark prices used in the calculation.

Year	WTI Crude Oil (US$/bbl)	Foreign Exchange Rate (US$/Cdn$)	Edmonton Par Crude Oil (Cdn$/bbl)	AECO Natural Gas (Cdn$/MMBtu)
2011	88.40	0.93	93.08	4.04
2012	89.14	0.93	93.85	4.66
2013	88.77	0.93	93.43	4.99
2014	88.88	0.93	93.54	6.58
2015	90.22	0.93	94.95	6.69
Average annual increase, thereafter	1.5%	-	1.5%	1.5%

4. Property Acquisition

On February 17, 2010, Freehold closed an acquisition of certain royalty interests in Alberta, Saskatchewan, and British Columbia for $38.2 million, including adjustments. The acquisition was effective October 1, 2009 and was funded through existing credit facilities.

5. Long-Term Debt

Freehold has a $195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which $65 million was drawn at December 31, 2010. In addition, Freehold has available a $15 million extendible revolving operating facility.

The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice. The facilities are extendible annually with the latest review completed in May 2010. Freehold's borrowing base is dependent on the lenders' annual review and interpretation of Freehold's reserves and future commodity prices, with the next renewal to occur by May 2011. In the event that the lenders do not consent to an extension, the revolving credit facility would revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period, which is May 2011.

Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins 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, 2010, the fair value of the long-term debt approximated its carrying value. The average effective interest rate on advances under the credit facility for the year ended December 31, 2010 was 3.1% (2009 – 2.4%).

6. Asset Retirement Obligation

Freehold has no asset retirement obligation on its royalty interest properties. Freehold's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The undiscounted value of Freehold's total asset retirement obligation is estimated to be $22.6 million. Payments to settle the obligations are expected to occur continuously over the next 60 years, with the majority of obligations being settled between 10 to 30 years away. A credit adjusted risk free rate ranging from 5% to 6% and an inflation rate of 1.5% (2009 – 2.0%) were used to calculate the fair value.

($000s)		2010		2009
Balance, beginning of year	$	7,160	$	5,663
Liabilities incurred		488		485
Liabilities settled		(346)		(173)
Revision in estimates (1)		(662)		852
Accretion expense		427		333
Balance, end of year	$	7,067	$	7,160

(1) Revision in estimates is mainly a result of changes in the inflation rate and abandonment years.

A reclamation fund, consisting of cash invested in an interest-bearing account, was established and funded by quarterly cash payments. All liabilities settled during the periods were paid from the reclamation fund. Subsequent to December 31, 2010, Freehold discontinued the use of the reclamation fund.

7. Shareholders' Capital

Freehold has authorized an unlimited number of common shares, without stated par value of which 59,181,312 were issued and outstanding at December 31, 2010 (2009 – 57,502,943 trust units).

Freehold has authorized 10,000,000 preferred shares, without stated par value, of which none have been issued.

SHARES AND TRUST UNITS ISSUED AND OUTSTANDING (INCLUDING EFFECTS OF THE REORGANIZATION)

	2010			2009		
	Number		Amount ($000s)	Number		Amount ($000s)
Trust unit balance, beginning of year	57,502,943	$	684,979	49,459,429	$	567,310
Issued in lieu of management fee (note 8)	169,411		3,016	148,597		2,018
Issued for deferred trust unit plan (note 9)	-		-	15,427		222
Issued for distribution reinvestment plan	1,508,958		25,695	260,740		3,906
Issued for equity offering	-		-	7,618,750		115,424
Issue costs, net of tax effect	-		-	-		(3,901)
Exchanged for shares per Reorganization	(59,181,312)		(713,690)	-		-
Trust unit balance, end of year	-		-	57,502,943	$	684,979
Common share balance, beginning of year	-		-	-		-
Exchanged for trust units per Reorganization	59,181,312		713,690	-		-
Elimination of deficit in accordance with the Reorganization	-		(448,608)	-		-
Common share balance, end of year	59,181,312	$	265,082	-		-

On December 31, 2010, pursuant to the Reorganization all outstanding trust units were exchanged for common shares on the basis of one common share for each trust unit held. In addition, shareholders' capital was reduced by $448.6 million, the amount necessary to eliminate the deficit of Freehold outstanding at the time of the Reorganization.

On December 10, 2009, Freehold closed an equity offering and issued 7,618,750 trust units at a price of $15.15 per trust unit for gross proceeds of $115.4 million. The issue costs 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, effective for the distribution payable on November 15, 2010 and thereafter. Previously, trust units issued in relation to the distribution reinvestment plan were purchased through the facilities of the Toronto Stock Exchange at prevailing market prices. During the Reorganization the plan was amended, but remained substantially the same, to be the dividend reinvestment plan (DRIP). At December 31, 2010 a balance of 730,302 shares were reserved for the DRIP.

Other shares reserved at December 31, 2010 include 300,000 for the deferred share unit plan (note 9) and 1,000,000 for the management fee (note 8).

8. Related Party Transactions

Freehold does not have any employees. The Manager of Freehold 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), which in turn is a shareholder of Freehold. The Manager recovers its general and administrative costs and a portion of its long-term incentive plan costs and retirement benefit costs, and receives a quarterly management fee paid in shares.

The Manager provides certain services for a fee based on a specified number of shares per quarter, pursuant to the amended and restated management agreement which has a term of three years and will be renewed in November 2013 unless terminated. During 2010, the management fee paid was 169,411 trust units with an ascribed value of $3.0 million (2009 – 148,597 trust units with an ascribed value of $2.0 million).

For the year ended December 31, 2010, the Manager charged Freehold $5.7 million (2009 – $5.7 million) in general and administrative 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 both parties.

9. Share Based and Other Compensation

(a) Manager's LTIP

Freehold participates in its proportionate share of a long-term incentive compensation plan for all employees of the Manager (the Manager's LTIP). The Manager's LTIP results in employees receiving cash compensation in relation to the value of a specified number of notional rights. The Manager's LTIP uses a combination of the value of phantom Rife shares and Freehold's common shares as the basis for rights, which are granted annually at the discretion of the directors of Rife and vest at the end of a three-year period. Dividends paid to shareholders by Freehold during the vesting period are assumed to be reinvested in notional rights on the dividend payment date. Upon vesting, the employee is entitled to a cash payout based on Freehold's share price. In addition, there is a performance multiplier based in part on Freehold's performance over the vesting period, which may range from 0.25 to 1.5 times the market value.

The total expensed for the year ended December 31, 2010 was $3.5 million (2009 – $2.9 million). At December 31, 2010, Freehold recorded $2.4 million (2009 – $2.0 million) as a deferred long-term compensation asset representing the portion of the liability not yet charged to earnings. In addition, Freehold accrued $5.4 million (2009 – $3.4 million) as a long-term liability and $2.3 million (2009 – $1.5 million) as a current liability.

(b) Deferred Share Unit Plan

Fully-vested deferred share units are granted annually to non-management directors. Dividends to shareholders declared prior to redemption are assumed to be reinvested in notional share units on the dividend payment date. As part of the Reorganization, the deferred trust unit plan was replaced with the deferred share unit plan. The plan is substantially the same with deferred trust units exchange for deferred share units. As at December 31, 2010, there were 73,750 (2009 – 53,070) deferred share units outstanding, which are redeemable for an equal number of common shares any time after a director's retirement.

DEFERRED SHARE UNITS

	December 31	
	2010	2009
Balance, beginning of year	53,070	44,087
Annual grants	13,916	22,577
Redeemed on a director's retirement	-	(22,038)
Additional resulting from distributions	6,764	8,444
Balance, end of year	73,750	53,070

For the year 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 year ended December 31, 2010, Freehold expensed $0.3 million (2009 - $0.4 million) as share based compensation with a corresponding increase to contributed surplus.

CONTRIBUTED SURPLUS

($000s)	December 31 2010	December 31 2009
Balance, beginning of year	$ 759	$ 722
Share based compensation expense	325	352
Deferred share units redeemed on a director's retirement	-	(315)
Balance, end of year	$ 1,084	$ 759

(c) Retirement Benefit

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

RECONCILIATION OF THE CHANGES IN THE PLAN'S BENEFIT OBLIGATIONS:

($000s)	December 31 2010	December 31 2009
Accrued benefit obligation, beginning of year	$ 405	-
Current service cost	58	504
Payments	(102)	(99)
Accrued benefit obligation, end of year	$ 361	405

10. Income and Capital Taxes

Freehold uses the liability method of accounting for income taxes, as described in note 1(e). The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to Freehold's earnings before income taxes. This difference results from the following items:

($000s, except as noted)	2010	2009
Income before income taxes and capital taxes	$ 34,492	$ 26,658
Combined federal and provincial tax rate	28.4%	29.4%
Computed expected income tax expense	$ 9,800	$ 7,834
Increase (decrease) in income tax resulting from:		
Non-taxable earnings	(19,378)	(16,437)
Effect of future rate changes	7,418	3,151
Share based and other compensation	93	104
Capital taxes	276	255
Other	10	10
Total income and capital taxes	$ (1,781)	$ (5,083)

The components of future income taxes at December 31 are as follows:

($000s)	2010	2009
Future income tax liabilities:		
Petroleum and natural gas interests	$ 36,621	$ 38,746
Future income tax assets:		
Asset retirement obligations	(1,788)	(1,855)
Trust unit issue expense	(754)	(755)
Net future income tax liability	$ 34,079	$ 36,136

On a consolidated basis, Freehold's carrying value for book purposes exceeds the amount available for tax purposes by $145 million.

Freehold's future tax liability relates primarily to the situation whereby its assets have a high book value relative to their associated tax value. This results in significant taxable temporary differences that reverse over time.

11. Other Income/Expense

In December 2009, a judgment of $2.1 million in Freehold's favour was received. The claim was based on Freehold's assertion of incorrect royalty payments and production from a terminated lease. Cash payment in full was received and recorded as income in 2009. In 2010, the defendant appealed the judgement. Upon ruling of the appeal in February 2011, the amount of damages was reduced and Freehold is to refund approximately $1.9 million. The liability and expense have been recorded in our December 31, 2010 financial statements.

12. Capital Management

Freehold is a publicly traded dividend paying corporation incorporated under the laws of the Province of Alberta and its primary focus is acquiring and managing oil and gas royalties. We receive revenue from oil and gas properties as reserves are produced, which is paid to shareholders on a regular basis over the economic life of the properties. Freehold's objective for managing capital is to maximize long-term shareholder value by distributing to shareholders any cash that is not required for financing our operations or capital investment growth opportunities that may offer shareholders better value.

We define capital as long-term debt, shareholders' equity, and working capital based on the consolidated financial statements. We manage our capital structure taking into account operating activities, debt levels, debt covenants, capital expenditures, and dividend levels. We also consider changes in economic conditions and commodity prices as well as the risk characteristics of our assets. We have a declining asset base, and ongoing development activities and acquisitions are necessary to replace production and add additional reserves. From time to time, we may issue shares or adjust capital spending to manage current and projected debt levels.

We retain working capital primarily to fund capital expenditures or acquisitions and reduce bank indebtedness. Freehold has chosen to issue its DRIP out of treasury which increases its flexibility with the use of working capital.

Management of Freehold's capital structure is facilitated through its financial and operating forecasting processes. The forecast of Freehold's future cash flows is based on estimates of production, commodity prices, forecast capital, royalty expenses, operating expenditures, and other investing and financing activities. The forecast is regularly updated based on new commodity prices and other changes which Freehold views as critical in the current environment. Selected forecast information is frequently provided to and approved by the Board of Directors.

We are bound by covenants on our credit facilities. The covenants are monitored monthly as part of management's internal review to ensure compliance with the requirements. Under our credit facility, we are restricted from paying dividends if we are or would be in default under the credit facility or if our borrowings thereunder exceed our borrowing base, currently set at $210 million. As at December 31, 2010, Freehold was in compliance with all such covenants (see note 5).

CAPITALIZATION

($000s, except as noted)	2010	2009
Shareholders' equity	$ 266,166	$ 298,972
Long term debt	65,000	45,000
Working capital deficency	6,479	3,082
Net debt	71,479	48,082
Cash provided by operating activities for last 12 months	110,693	95,659
Change in non-cash operating working capital	(3,722)	(574)
Trailing 12 months funds generated from operations	106,971	95,085
Net debt to trailing 12 month funds generated from operations (times)	0.7	0.5

13. Financial Instrument Risk Management

Freehold has exposure to credit, liquidity, and market risks from its use of financial instruments. We employ the following strategies to mitigate these risks.

(i) Credit risk

Credit risk is the risk of financial loss to Freehold if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from our receivables. A large part of our accounts receivable are with oil and gas industry operators, either as joint venture partners or as payors of various royalty agreements. Our diversified revenue stream limits the size of any one property or industry operator with respect to total receivables.

We maintain an aggressive auditing program to ensure that we are paid royalties on our production from our lands in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken.

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. We did not have an allowance for doubtful accounts as at December 31, 2010 and December 31, 2009 and did not provide for any doubtful accounts nor were we required to write off any receivables during the years ended December 31, 2010 and 2009.

Freehold markets approximately 60% of its production along with the operator or royalty payor under the terms of a diverse number of agreements. When it can, Freehold takes its production in kind (currently approximately 40%) and sells to two primary purchasers.

(ii) Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We maintain a conservative approach to debt management that aims to provide maximum financial flexibility with respect to acquisitions and development expenditures, while maintaining stable dividend payments. At December 31, 2010, there was $145 million of available capacity under our credit facilities. As circumstances warrant, we allocate a portion of cash provided by operating activities to debt repayment. We prepare annual capital expenditure budgets, which are regularly monitored and updated.

(iii) Market risk

Market risk is the risk that changes in market prices, such as foreign currency exchange rates, commodity prices, and interest rates, will affect net income or the value of financial instruments. For short-term investments, we select counterparties based on credit ratings and monitor all investments to ensure a stable return, avoiding complex investment vehicles with higher risk such as asset-backed commercial paper.

Foreign currency exchange rate risk

We do not sell or transact in any foreign currency; however, the underlying market prices in Canada for oil and natural gas are influenced by changes in the exchange rate between the Canadian and U.S. dollar. During the year ended December 31, 2010, we had no foreign exchange related derivative contracts in place. Assuming all other variables held constant, a $0.01 change (plus or minus) in the U.S./Canadian dollar exchange rate for the year ended December 31, 2010, would have resulted in a corresponding change to net income of approximately $1.4 million (2009 – $1.3 million).

Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate with changes in commodity prices. Commodity prices for oil and natural gas are influenced by the relationship between the Canadian and U.S. dollar as well as macroeconomic events that dictate the levels of supply and demand. During the year ended December 31, 2010, we had no commodity price related derivative contracts in place. Assuming all other variables held constant, a US$1.00 change (plus or minus) in the WTI crude oil price for the year ended December 31, 2010, would have resulted in a corresponding change to net income of approximately $1.4 million (2009 – $1.5 million). A $0.25 change (plus or minus) in the AECO natural gas price would have resulted in a corresponding change to net income of approximately $1.4 million (2009 – $1.2 million).

Interest rate risk

We are exposed to interest rate risk on outstanding bank debt, which has a floating interest rate, and fluctuations in interest rates would impact our future cash flows. Assuming all other variables held constant, a 1% change (plus or minus) in the interest rate for the year ended December 31, 2010 would have resulted in a corresponding change to net income of approximately $0.7 million (2009 – $1.5 million).

14. Supplemental Cash Flow Disclosure

CHANGES IN NON-CASH WORKING CAPITAL BALANCE

($000s)		2010		2009
Accounts receivable	$	1,425	$	(795)
Accounts payable and accrued liabilities		883		3,783
	$	2,308	$	2,988

($000s)		2010		2009
Operating	$	3,722	$	574
Investing		(1,414)		2,414
	$	2,308	$	2,988

CASH EXPENSES PAID

($000s)		2010		2009
Interest	$	3,625	$	4,375
Taxes		108		494

15. Contingency

In May 2009, a statement of claim was filed against Freehold for $9 million. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, Freehold 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 and therefore, no liability has been recorded in the financial statements.

16. Comparative Figures

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

Board of Directors

D. Nolan Blades, Calgary, Alberta
Director since 1996
Chair of the Board
Committees: Audit and Compensation

Nolan Blades is President of Sunny Gables Holdings Ltd. (Calgary). He holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer. Mr. Blades was President and CEO of Pursuit Resources Corp. from 1993 to 2000, prior to which he held senior executive positions with Chauvco Resources Ltd. and Oakwood Petroleum Ltd.

Harry S. Campbell, Q.C. Calgary, Alberta
Director since 1996
Committees: Governance and Nominating, and Reserves

Harry Campbell is Vice-Chair of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974 and has extensive experience with Canadian oil and gas transactions and international petroleum and natural gas matters.

Tullio Cedraschi, Montreal, Quebec
Director since 1998
Committees: Governance and Nominating

Tullio Cedraschi is a Corporate Director and former President and CEO of the CN Investment Division (Montreal). He is Governor Emeritus of McGill University, and Governor of the National Theatre School of Canada. He holds an MBA from McGill University.

Peter T. Harrison, Montreal, Quebec
Director since 1996
Committees: Reserves

Peter Harrison is Manager, Canadian Equities and Oil & Gas Investments for the CN Investment Division (Montreal). Previously he was Senior Vice-President of Montrusco Bolton Inc. He holds a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario and is a Chartered Financial Analyst.

William O. Ingram, Calgary, Alberta
Director since 2009

William Ingram is President and CEO of Freehold Royalties Ltd. and Rife Resources Ltd. (Calgary). Prior to joining Rife in 1984, he held senior engineering positions with Amoco Canada Petroleum Company Ltd. Mr. Ingram holds a Bachelor of Science degree in Chemical Engineering from the University of Alberta and is a Professional Engineer.

P. Michael Maher, Calgary, Alberta
Director since 1996
Committees: Audit, Compensation (Chair), and Governance and Nominating (Chair)

Michael Maher is a Professional Engineer, Professor and former Dean of the Haskayne School of Business, University of Calgary. He holds a Bachelor of Science degree in Engineering from the University of Saskatchewan, an MBA from the University of Western Ontario, a Ph.D. from Northwestern University, and a Doctor of Commerce degree (honoris causa) degree from St. Mary's University.

David J. Sandmeyer, Calgary, Alberta
Director since 1996
Committees: Reserves (Chair)

David Sandmeyer is a Corporate Director and former President and CEO of Freehold Resources Ltd. and Rife Resources Ltd. (Calgary). Prior to joining Rife in 1982, he held senior positions with Amoco Canada Petroleum Company Ltd. A graduate of the University of Saskatchewan, he holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer.

Rodger A. Tourigny, Calgary, Alberta
Director since 2009
Committees: Audit (Chair) and Compensation

Rodger Tourigny is President of Tourigny Management Ltd., a private consulting company (Calgary). He has been providing consulting services since 1979 primarily dealing with oil and gas, financial services and real estate. He holds a Bachelor of Commerce degree from the University of Saskatchewan and is a Chartered Accountant.

Corporate Information

Head Office

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Manager, Investor Relations and
Corporate Secretary

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Officers

D. Nolan Blades
Chair of the Board

William O. Ingram
President and Chief Executive Officer

Garry W. Bieber
Vice-President, Production

J. Frank George
Vice-President, Exploration

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

The Manager

Rife Resources Management Ltd.
w. rife.com

Legal Counsel

Burnet Duckworth & Palmer, LLP
Calgary, Alberta

Auditors

KPMG LLP
Calgary, Alberta

Bankers

Canadian Imperial Bank of Commerce
Calgary, Alberta

Royal Bank of Canada
Calgary, Alberta

The Toronto-Dominion Bank
Calgary, Alberta

Reserve Evaluators

Trimble Engineering Associates Ltd.
Calgary, Alberta

Stock Exchange and Trading Symbol

Toronto Stock Exchange (TSX)
Common Shares: FRU

Annual Meeting

The Annual Meeting of the Shareholders ~~Unitholders~~ of Freehold will be held at 3:30 pm (MDT)
on May 11, 2011
at Sun Life Plaza Conference Centre, Calgary, Alberta

Freehold Royalties Ltd. ~~Freehold Royalty Trust~~ is a dividend paying oil and gas company ~~income trust~~ based in Calgary, Alberta. Our royalty interests are a major contributor to our operating and financial performance and are not subject to expenses such as operating and capital costs. Our assets generate income from crude oil, natural gas, natural gas liquids, and potash. Growth is achieved through ongoing development activity on our extensive land base spanning 2.8 million gross acres, and through acquisitions.

Freehold's shares ~~trust units~~ are listed for trading on the Toronto Stock Exchange under the trading symbol FRU.~~UN~~.

Freehold

ROYALTIES LTD.

400, 144 – 4th Avenue SW
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freehold~~trust.com~~royalties.com