Freehold Royalties Ltd.

2011 FINANCIAL REPORT

Here's the dirt.

We're not your typical oil and gas company.

We own one of the largest non-Crown portfolios of oil and gas royalties in Canada.

We collect royalties from the companies that operate on our lands. This lowers our risk and ensures a steady revenue stream.

We pay an attractive monthly dividend to our shareholders.

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Freehold
ROYALTIES LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis (MD&A) was prepared as of March 14, 2012, and is management's opinion about the consolidated operating and financial results of Freehold Royalties Ltd. and its wholly-owned subsidiaries (Freehold) for the year ended December 31, 2011 and previous periods, and the outlook for Freehold based on information available as of the date hereof.

The financial information contained herein was based on information in the consolidated financial statements, which have been prepared in accordance with International Financial Reporting Standards (IFRS), which are the new Canadian generally accepted accounting principles (GAAP) for publicly accountable enterprises. All comparative percentages are between the years ended December 31, 2011 and 2010, 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.

This MD&A contains non-GAAP financial measures and forward-looking statements that are intended to help readers better understand our business and prospects. Readers are cautioned that the MD&A should be read in conjunction with our disclosure under "Non-GAAP Financial Measures" and "Forward-Looking Statements" included at the end of this MD&A.

MD&A CONTENTS

TRANSITION TO IFRS

The Canadian Accounting Standards Board has incorporated IFRS, as adopted by the International Accounting Standards Board, into Part I of the Handbook of the Canadian Institute of Chartered Accountants as GAAP for Canadian publicly accountable enterprises.

Freehold's results reflect the adoption of IFRS effective January 1, 2011. Adoption required restatement, for comparative purposes, of amounts reported for the year ended December 31, 2010, including our opening balance sheet as at January 1, 2010. Our conversion to IFRS increased 2010 net income by 36% but had no material impact on our operating cash flows. Further details are included later in this MD&A and in note 18 of our 2011 consolidated financial statements.

CORPORATE CONVERSION

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. 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 a dividend-paying corporation incorporated under the laws of the Province of Alberta and trades on the Toronto Stock Exchange under the symbol FRU. Freehold is directly and indirectly involved in the development and production of crude oil and natural gas predominantly in western Canada. We receive revenue from oil and gas properties as reserves are produced over the economic life of the properties. Our primary focus is acquiring and managing oil and gas royalties.

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. Our royalty land holdings encompass 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 more than 630,000 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, while we benefit from the drilling activity of others. Royalties offer the benefit of sharing in production revenue without exposure to the capital costs, operating expenses, and environmental costs typically associated with oil and gas operations. As a royalty interest owner, we do not pay any of the capital costs to drill and equip the wells for production, nor do we incur costs to operate the wells, maintain production, and ultimately restore the land to its original state. All of the costs are paid by others. On the majority of our production, we receive royalty income from gross production revenue (revenue before any royalty or operating expenses are deducted). Our high percentage of royalty production (75% in 2011) results in strong netbacks.

We also hold working interests in 179,300 gross (27,962 net) acres. Our largest working interest property is Southeast Saskatchewan, which produced an average of 661 boe per day in 2011, or 35% of our total working interest production volumes. We also have various working interests in 106 other properties.

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:

- Acquire additional assets with a bias toward royalty interests.
- 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.
- 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 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 day-to-day management, 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 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.

2011 HIGHLIGHTS

Freehold's assets delivered strong results in 2011, despite commodity price volatility and the lingering effects of wet summer operating conditions. Our 63% oil-weighted production continued to benefit from robust oil prices while our diversified portfolio served to mitigate the impact of low natural gas prices. Revenue, net income, and funds from operations were substantially higher than last year. Per share amounts reflect increased participation in our dividend reinvestment plan (DRIP) during 2011; participation averaged 33% in 2011 (2010 – 26%), allowing us to conserve $33.5 million in dividend payments by issuing shares from treasury.

ANNUAL HIGHLIGHTS

($000s, except as noted)	**2011**	2010	Change
Gross revenue	**157,910**	138,155	14%
Revenue, net of royalty expenses	**153,713**	134,063	15%
Net income	**55,259**	49,349	12%
Per share, basic and diluted ($)	**0.92**	0.85	8%
Funds from operations (1)	**128,230**	106,971	20%
Per share ($)	**2.14**	1.83	17%
Total assets	**423,440**	427,502	-1%
Long-term debt	**48,000**	65,000	-26%
Total long-term liabilities	**123,148**	116,588	6%
Dividends declared	**100,968**	98,115	3%
Per share ($) (2)	**1.68**	1.68	0%
Average shares outstanding (000s) (3)	**60,022**	58,334	3%

(1) See Non-GAAP Financial 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.

OUTLOOK

Business Environment

In 2011, the benchmark West Texas Intermediate (WTI) crude oil prices averaged 20% higher than in 2010, but with continued volatility due to global economic and political uncertainties, including the U.S. debt ceiling impasse, unrest in the Middle East and Africa, the European debt crisis, and a cooling of the Chinese economy. A transportation bottleneck out of North American inland markets (exacerbated by rising U.S. Bakken oil production and increasing oil sands volumes) has served to dislocate the WTI crude oil benchmark from other light oil benchmarks such as European Brent Crude, creating a significant price discount for WTI. In turn, this is serving to widen the discount for Canadian (Edmonton Par) light crude oil relative to WTI. However, it is anticipated that rail and pipeline projects will be commissioned within the next few years to link U.S. and Canadian oil production to U.S. Gulf Coast refining centres, where international prices prevail.

The Canadian light/heavy oil price differential widened to an average of $17.93 per boe in 2011 from $10.27 per boe in 2010. The differential narrowed during the fourth quarter, but continues to rise and fall in response to domestic supply and demand factors.

Historically, the benchmark Western Canada Select (WCS) heavy oil stream, with an average API gravity of 20.5 degrees, was considered a rough proxy for our average oil price. In 2011, our average oil price increased in relation to the benchmark WCS. Oil prices and differentials are expected to remain volatile in the short term, with both upside and downside risks.

Natural gas, because it is less readily transported, is subject to supply and demand factors within North America. The benchmark AECO natural gas price declined 11% in 2011. The outlook for natural gas prices remains bearish in the near term as North American supply continues to grow, while demand remains soft due to a warmer than expected winter. However, the low price environment has prompted some natural gas producers to shut in production until prices improve, and we believe the supply/demand balance will gradually improve. Projects are underway to open access to high-demand Asian markets as early as 2015. In 2011, the National Energy Board granted a 20-year export licence to Kitimat LNG to ship liquefied natural gas from Canada to international markets, and approvals are also in place for the construction of the Pacific Trail Pipeline, which will connect natural gas from the Western Canada Sedimentary Basin to the Kitimat LNG facility at Bish Cove, British Columbia.

Overall, the outlook for crude oil is more favourable than for natural gas, and industry activity has shifted toward oil development, with natural gas drilling focused on resource plays containing high liquids content. 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. A single horizontal well, completed with multiple fractures, can access as much reservoir as several vertical wells, potentially yielding more production and reserves per well.

The Canadian Association of Oilwell Drilling Contractors (CAODC) reported a total of 16,081 wells drilled in western Canada (on a “wells completed” basis) in 2011, up 18% from 13,575 wells in 2010. The well counts reflect strong activity levels, despite a dramatic reduction in the number of natural gas wells. The CAODC’s 2012 forecast (issued in November 2011) projects stable activity levels for 2012, noting that the industry will continue to be challenged by a shortage in skilled manpower, especially as 35-40 large capacity drilling rigs are expected to be commissioned in 2012. These rigs are being built to serve the horizontal drilling market.

Nearly 60% of the net wells drilled on our royalty lands in 2011 were horizontal wells, up from 37% in 2010. Continued success with horizontal drilling (for both oil and liquids-rich natural gas) on our royalty lands is positive and bodes well for improved well productivity. Given our diverse land base, we are well positioned to participate in many of the resource plays employing horizontal drilling throughout the Western Canada Sedimentary Basin. 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 108,000 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.

2012 Plans

As previously announced, on January 17, 2012 we acquired certain royalty interests for $49.6 million before closing adjustments. The acquisition was funded through our existing bank line of credit.

On February 29, 2012, we closed an equity offering, issuing 3.5 million shares (including the exercise in full of the underwriters’ over-allotment option) at $20.50 per share. Net proceeds of $67.6 million were used to repay the bank indebtedness associated with the acquisitions completed on September 30, 2011 and January 17, 2012.

We currently have approximately $185 million of available capacity under our credit facilities, which gives us significant financial flexibility to take advantage of acquisition opportunities. We believe producers may look to sell non-core oil and gas assets, and particularly royalty interests, in order to reduce debt and fund their core exploration and development programs. In addition, cash preserved through our DRIP continues to enhance our capital resources.

We have maintained a steady monthly dividend rate of $0.14 ($1.68 annually) per share since January 2010. Based on our current guidance, we expect to maintain this monthly dividend rate through 2012, subject to the Board's quarterly review.

For 2012, the Board has approved a capital budget of $30 million. Our plans include 60 (16.5 net) wells, of which 44% will be operated. About 80% of our capital will be deployed on our mineral title lands in Southeast Saskatchewan, where we continue to see opportunities. Spending may be adjusted as the year progresses, depending on the operating environment and well results. Based on this level of capital investment, anticipated drilling activity on our leased royalty lands, and normal production declines (and excluding any future acquisitions), we expect 2012 production to average approximately 7,600 boe per day. Our production remains unhedged, subject to quarterly review by our Board.

Our key operating assumptions for 2012 are outlined below.

2012 KEY OPERATING ASSUMPTIONS

As at March 14, 2012		
Average daily production	boe/d	7,600
Average WTI oil price	US$/bbl	100.00
Average exchange rate	Cdn$/US$	1.00
Average heavy oil differential (1)	Cdn$/bbl	(18.00)
Average AECO natural gas price	Cdn$/Mcf	2.50
Average operating costs	$/boe	4.60
Average general and administrative costs (2)	$/boe	3.00
Capital expenditures	$ millions	30
Proceeds from DRIP (3)	$ millions	27
Long-term debt at year end	$ millions	15
Cash taxes payable in 2012 (4)	$ millions	2
Current income tax expense (payable in 2013) (4)	$ millions	21
Weighted average shares outstanding	millions	65

(1) The difference between the Edmonton Par and Western Canada Select crude oil streams.
(2) Excludes share based and other compensation.
(3) Average 25% participation rate, which is subject to change.
(4) Corporate tax estimates will vary depending on commodity prices and other factors. See discussion under Income Tax.

Recognizing the cyclical nature of the oil and gas 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 have no operational control and do not know the future plans of the various operators.

A sensitivity analysis of the potential impact of key variables on funds from operations per share 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.

2012 SENSITIVITY ANALYSIS

Variable	Change (+/-)	Estimated Change in Funds from Operations ($/share)
WTI oil price	US$1.00/bbl	0.02
Canadian/U.S. dollar exchange rate	US$0.01	0.02
Light/heavy oil price differential (1)	Cdn$1.00/bbl	0.02
AECO natural gas price	Cdn$0.25/Mcf	0.02
Interest rate	1%	0.00
Oil and NGL production	100 bbls/d	0.03
Natural gas production	1,000 Mcf/d	0.01

(1) Calculations are performed independently and may not be indicative of actual results that would occur when multiple variables change at the same time.
(2) See non-GAAP Financial Measures.
(3) The difference between the Edmonton Par and Western Canada Select crude oil streams.

QUARTERLY PERFORMANCE

Fourth Quarter Highlights

Freehold's assets delivered strong results in the fourth quarter. Our 65% oil-weighted production continued to benefit from robust oil prices, while our diversified portfolio served to mitigate the impact of lower natural gas prices. Revenue, operating netback, and funds from operations were all substantially higher than the fourth quarter of 2010. Per share amounts reflect increased participation in our DRIP; average participation was 40% in the fourth quarter (Q4 2010 – 28%), allowing us to conserve $10.2 million in dividend payments by issuing shares from treasury.

- Gross revenue increased 24%, mainly due to higher oil prices. Average price realizations were $61.90 per boe, up 27%, and average production was 7,773 boe per day, down 2% from the fourth quarter of 2010.
- Net income rose 41% due to higher oil prices despite an increase in deferred income tax as a result of converting from a trust structure to a corporation. Non-cash charges included in net income amounted to $22.3 million (Q4 2010 – $16.9 million).
- Funds from operations rose 36% and on a per share basis rose 31%.
- Dividends for the fourth quarter of 2011 totalled $0.42 per share, unchanged from the fourth quarter of 2010.
- Net capital expenditures (working interests) totalled $10.9 million, or 29% of funds from operations.
- The ratio of net debt to annual funds from operations was 0.4 times and net debt was approximately 15% of total capitalization at the end of 2011.
- Oil and natural gas liquids (NGL) production rose 6% in the fourth quarter, while natural gas production declined 15%. The fourth quarter benefitted from production additions of approximately 125 boe per day, mostly oil, from the royalty acquisition completed on September 30, 2011. Production in the fourth quarter of 2011 also included positive prior period adjustments of approximately 350 boe per day, mostly oil. The fourth quarter of 2010 included a number of prior period adjustments as well, that increased royalty interest natural gas volumes in the comparative period by approximately 2,700 Mcf (450 boe) per day.
- While natural gas production accounted for 35% of production in the fourth quarter, it comprised only 10% of revenue.

Quarterly 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, and funds 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 were generally stronger in 2011 compared to 2010, although prices exhibited short-term volatility due to global geo-political events. Fluctuations in foreign exchange rates also affected our oil price realizations, resulting in both positive and negative effects on our Canadian dollar oil revenues relative to the benchmark WTI, which is referenced in U.S. dollars.
- Heavy oil prices remained strong in the first half of 2010, due to high demand related to line fill requirements for the start-up of TransCanada's Keystone pipeline. Later in 2010, however, disruptions in Enbridge's oil pipeline network curtailed Canadian shippers' access to U.S. refineries. The resulting supply glut in Canada caused heavy oil differentials to widen significantly. Residual pipeline capacity constraints continued to weigh on the price of Canadian heavy crude through 2011, although price differentials narrowed in the fourth quarter. Domestic demand for heavy oil is typically lower during the winter and highest during the summer paving season.
- With supply outstripping demand, AECO natural gas prices exhibited significant volatility and have remained weak over the past eight quarters. 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.
- On September 30, 2011, we closed a $7.3 million royalty acquisition; and on February 17, 2010, we closed a $39 million royalty acquisition. Both acquisitions were funded through our existing credit facilities.
- In November 2009, we began issuing shares from treasury for the DRIP instead of purchasing them in the market. Participation in the DRIP has increased in recent months, averaging approximately 33% in 2011.
- Per share amounts reflect issuances from treasury due to increased participation in the DRIP and payment of the quarterly management fee in shares.
- Due to the large number of wells in which we have royalty interests, the nature of royalty interests, the lag in receiving production receipts from the operators, and our audit program, our reported royalty volumes usually include adjustments (both positive and negative) for prior periods. In the fourth quarter of 2010, prior period adjustments increased production by approximately 2,700 Mcf (450 boe) per day. In the second quarter of 2011, prior period adjustments increased production by approximately 400 boe per day, mostly natural gas and natural gas liquids (NGL). In the fourth quarter of 2011, prior period adjustments were mostly oil-related and increased production by approximately 350 boe per day.
- In the first quarter of 2011, we recorded a one-time adjustment relating to the payout of a natural gas well in Alberta. The payout resulted in a reduction of our working interest in the well retroactive to 2009. The cumulative impact was recorded in the first quarter of 2011, effectively reducing natural gas volumes by approximately 600 Mcf (100 boe) per day.
- 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.
- Payments under the long-term incentive plan (LTIP), which are payable in the first quarter every year, reduced funds from operations by $2.3 million in the first quarter of 2011 (Q1 2010 – $1.5 million).

The accompanying table illustrates the fluctuations experienced over the past eight quarters and the resulting effect on our financial results. Additional information about our quarterly results is provided in our interim reports, copies of which are available on SEDAR and on our website.

QUARTERLY REVIEW

	2011				2010			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Financial ($000s, except as noted)								
Revenue, net of royalty expense	**44,217**	**34,614**	**39,560**	**35,322**	35,525	31,732	31,524	35,282
Dividends declared	**25,585**	**25,322**	**25,111**	**24,950**	24,797	24,617	24,436	24,265
Per share ($) (1)	**0.42**	**0.42**	**0.42**	**0.42**	0.42	0.42	0.42	0.42
Net income (2)	**16,321**	**11,290**	**16,717**	**11,219**	11,387	12,999	13,621	11,342
Per share, basic and diluted ($) (2)	**0.27**	**0.19**	**0.28**	**0.19**	0.19	0.22	0.23	0.20
Funds from operations (3)	**38,245**	**28,772**	**33,891**	**27,322**	28,218	25,811	25,197	27,745
Per share ($) (3)	**0.63**	**0.48**	**0.57**	**0.46**	0.48	0.44	0.43	0.48
Proceeds from the DRIP	**10,232**	**8,765**	**7,798**	**6,695**	6,845	6,648	6,178	6,023
Property and royalty acquisitions (net)	**(195)**	**7,297**	**44**	**321**	283	(153)	71	38,399
Capital expenditures	**10,910**	**5,537**	**4,537**	**4,665**	4,664	6,003	4,735	2,652
Long-term debt	**48,000**	**51,000**	**54,000**	**61,000**	65,000	70,000	73,000	78,000
Shares outstanding								
Weighted average (000s)	**60,811**	**60,198**	**59,716**	**59,343**	58,972	58,536	58,112	57,700
At quarter end (000s)	**61,141**	**60,492**	**59,954**	**59,536**	59,181	58,781	58,335	57,926
Operating ($/boe, except as noted)								
Daily production (boe/d) (4)	**7,773**	**7,195**	**7,445**	**7,490**	7,972	7,495	7,655	7,331
Royalty interest production (%)	**74**	**72**	**77**	**76**	74	73	73	73
Average selling price	**61.90**	**52.80**	**57.61**	**52.51**	48.80	46.44	45.56	54.45
Operating netback (3)	**56.56**	**46.86**	**53.82**	**48.96**	44.57	41.56	40.96	49.44
Operating expenses	**5.28**	**5.43**	**4.57**	**3.44**	3.87	4.46	4.29	4.03
Working interest properties	**19.91**	**19.47**	**19.73**	**14.32**	14.72	16.27	15.99	15.10
Net general and administrative expenses (5)	**2.05**	**2.16**	**2.36**	**3.75**	2.27	2.67	2.56	3.81
Benchmark Prices								
WTI crude oil (US$/bbl)	**94.06**	**89.75**	**102.56**	**94.02**	85.16	76.16	78.03	78.71
Exchange rate (US$/Cdn$)	**0.98**	**1.02**	**1.03**	**1.01**	0.99	0.96	0.97	0.96
Edmonton Par crude oil (Cdn$)	**97.35**	**91.74**	**103.07**	**87.97**	80.33	74.44	75.19	80.08
Western Canada Select (Cdn$/bbl)	**85.48**	**70.63**	**82.09**	**70.19**	67.86	62.91	65.62	72.54
Light/heavy oil differential (Cdn$/bbl) (6)	**11.87**	**21.11**	**20.98**	**17.78**	12.47	11.53	9.57	7.54
AECO natural gas (Cdn$/Mcf)	**3.47**	**3.72**	**3.74**	**3.77**	3.58	3.71	3.86	5.36
Share Trading Performance								
High ($)	**19.75**	**21.58**	**23.28**	**22.93**	21.14	17.90	18.05	17.59
Low ($)	**14.51**	**16.04**	**19.37**	**19.86**	17.75	15.73	15.31	15.08
Close ($)	**19.41**	**16.36**	**19.64**	**22.75**	20.49	17.89	15.84	16.94
Volume (000s)	**7,114**	**7,780**	**5,317**	**7,921**	7,279	4,515	6,029	7,943

(1) Based on the number of shares issued and outstanding at each record date.
(2) Net income and net income per share for the three months ended March 31, 2011 have been restated for revisions made to deferred tax.
(3) See Non-GAAP Financial Measures.
(4) Dividends paid in shares pursuant to the DRIP. See Liquidity and Capital Resources – Dividends Paid.
(5) Reported production for a period may include minor adjustments from previous production periods.
(6) Excludes share based and other compensation.
(7) 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, the lag in receiving production receipts, and our audit program, our reported royalty volumes usually include adjustments for prior periods.

On a boe basis, our production declined 2% in 2011, as drilling activity and acquisitions were insufficient to fully offset natural production declines. Royalty interests comprised 75% (2010 – 73%) of total volumes produced in 2011. Working interest volumes were affected by declining oil volumes at Hayter, where our infill drilling program, now in its tenth year, is yielding less production. In addition, due to wet weather in the first half of 2011, development activities in Southeast Saskatchewan occurred in the latter part of the year. Our production mix for 2011 was approximately 37% natural gas and 63% liquids (28% heavy oil, 30% light and medium oil, and 5% NGL).

PRODUCTION SUMMARY

(boe/d)	**2011**	2010	Change
Royalty interest	**5,578**	5,573	0%
Working interest	**1,898**	2,042	-7%
Total	**7,476**	7,615	-2%

AVERAGE DAILY PRODUCTION BY PRODUCT TYPE

	2011	2010	Change
Light and medium oil (bbls/d)	**2,301**	2,073	11%
Heavy oil (bbls/d)	**2,057**	2,279	-10%
NGL (bbls/d)	**339**	352	-4%
Total oil and NGL (bbls/d)	**4,697**	4,704	0%
Natural gas (Mcf/d)	**16,674**	17,465	-5%
Oil equivalent (boe/d)	**7,476**	7,615	-2%
Total annual production (Mboe)	**2,729**	2,779	-2%
Potash (tonnes/d)	**12**	12	0%

PRODUCTION RECONCILIATION

(boe/d)	Royalty Interest	Working Interest	**Total**
2010 average daily production rate	5,573	2,042	**7,615**
2010 activities, full year impact	323	501	**824**
2011 development	306	304	**610**
2011 acquisitions	25	-	**25**
Natural decline	(649)	(949)	**(1,598)**
2011 average daily production rate	5,578	1,898	**7,476**

Product Prices

The following table is a summary of average benchmark prices.

AVERAGE BENCHMARK PRICES (1)

	2011	2010	Change
WTI crude oil (US$/bbl)	**95.10**	79.53	20%
Exchange rate (US$/Cdn$)	**1.01**	0.97	4%
Edmonton Par crude oil (Cdn$/bbl)	**95.03**	77.50	23%
Western Canada Select (Cdn$/bbl)	**77.10**	67.23	15%
Light/heavy oil differential (Cdn$/bbl) (2)	**17.93**	10.27	75%
AECO natural gas (Cdn$/Mcf)	**3.66**	4.13	-11%

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

The price we receive for our production is primarily driven by the U.S. dollar price of West Texas Intermediate (WTI), adjusted to western Canada. Therefore, an increase in the value of the Canadian dollar relative to the U.S. dollar will reduce the revenue received. Approximately 28% of our production is heavy crude, which trades at a discount to light crude.

WCS is made up of existing Canadian heavy conventional and bitumen crude oils blended with sweet synthetic and condensate diluents. Historically, the benchmark WCS heavy oil stream, with an average API gravity of 20.5 degrees, was considered a rough proxy for our average oil price realizations. However, in 2011 our average oil realizations increased in relation to the benchmark WCS.

Our average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average selling price was 16% higher in 2011 because of higher average oil prices, despite a slightly weaker U.S. dollar and wider heavy oil differentials compared to 2010.

AVERAGE SELLING PRICES

	2011	2010	Change
Oil ($/bbl)	**79.23**	66.54	19%
NGL ($/bbl)	**69.51**	51.33	35%
Oil and NGL ($/bbl)	**78.53**	65.40	20%
Natural gas ($/Mcf)	**3.13**	3.64	-14%
Oil equivalent ($/boe)	**56.31**	48.74	16%
Potash ($/tonne)	**532.14**	400.90	33%

Marketing and Hedging

Our production remained unhedged in 2011, 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 Interests

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. Some of our leases allow us to take our oil production in-kind. As at December 31, 2011, we were marketing approximately 30% of our royalty oil production using 30-day contracts.

Working Interests

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 Expense

Gross revenue in 2011 was 14% higher than in 2010 due to higher realized oil prices, despite continued low natural gas prices. 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 judgment. Upon ruling of the appeal in February 2011, the amount of damages was reduced and Freehold refunded approximately $1.9 million.

REVENUE AND OTHER EXPENSE

($000s)	**2011**	2010	Change
Gross revenue	**157,910**	138,155	14%
Royalty and mineral tax expense (1)	**(4,197)**	(4,092)	3%
Net revenue	**153,713**	134,063	15%
Other income (expense)	-	(1,850)	-100%

(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 2011, offset in part by the effect of lower natural gas prices.

GROSS REVENUE VARIANCES

($000s)	**2011 vs. 2010**	2010 vs. 2009
Oil and NGL		
Production increase (decrease)	**(213)**	109
Price increase	**22,538**	15,804
Net increase	**22,325**	15,913
Natural gas		
Production increase (decrease)	**(904)**	2,456
Price decrease	**(3,232)**	(162)
Net increase (decrease)	**(4,136)**	2,294
Other revenue increase (decrease) (1)	**1,566**	(17)
Gross revenue increase	**19,755**	18,190

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

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 2011 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.

ROYALTY EXPENSE AND MINERAL TAX (1)

($000s, except as noted)	**2011**	2010	Change
Working interest			
Crown royalties	**2,950**	2,583	14%
Third party royalties (2)	**783**	1,065	-26%
Mineral tax	**278**	250	11%
Working interest	**4,011**	3,898	3%
Per boe ($)	**5.79**	5.23	11%
Royalty interest			
Crown royalties	**-**	-	-
Third party royalties (2)	**-**	-	-
Mineral tax	**186**	194	-4%
Royalty interest	**186**	194	-4%
Per boe ($)	**0.09**	0.10	-10%
Total	**4,197**	4,092	3%
Per boe ($)	**1.54**	1.47	5%
As a percentage of gross revenue	**3%**	3%	0%

(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 expenses and accounted for as a reduction to general and administrative (G&A) expenses. A percentage of operating expense is fixed and, as such, per boe operating expenses are highly variable to production volumes.

On a per boe basis, operating expense on working interest production rose 19% in 2011. The increase was attributable to a number of factors, including higher Alberta power costs, prior period adjustments, higher costs and a declining production base at Hayter, and wet weather in Southeast Saskatchewan during the second and third quarters of 2011.

OPERATING EXPENSES

($000s, except as noted)	**2011**	2010	Change
Working interest	**12,782**	11,569	10%
Per boe ($)	**18.45**	15.52	19%
Royalty interest (1)	**-**	-	-
Per boe ($)	**-**	-	-
Total operating expenses	**12,782**	11,569	10%
Per boe ($)	**4.68**	4.16	13%
As a percentage of gross revenue	**8%**	8%	0%

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

Operating Netback

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.

2011 NETBACK ANALYSIS

($000s)	Royalty Interest	Working Interest	**Total**
Gross revenue (1)	110,513	47,397	**157,910**
Royalty expense and mineral tax (2)	(186)	(4,011)	**(4,197)**
Net revenue	110,327	43,386	**153,713**
Operating expense	-	(12,782)	**(12,782)**
	110,327	30,604	**140,931**

($ per boe)			
Gross revenue (1)	54.29	68.40	**57.87**
Royalty expense and mineral tax (2)	(0.09)	(5.79)	**(1.54)**
Net revenue	54.20	62.61	**56.33**
Operating expense	-	(18.45)	**(4.68)**
Operating netback (3)	54.20	44.16	**51.65**

(1) Gross revenue includes potash, sulphur, lease rentals, processing fees, interest, and other income.
(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. See Non-GAAP Financial Measures.

OPERATING NETBACK

($ per boe)	**2011**	2010	Change
Royalty interest	**54.20**	46.98	15%
Working interest	**44.16**	36.13	22%
Total	**51.65**	44.08	17%

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

G&A expenses also include one-time costs associated with the transition to International Financial Reporting Standards (IFRS) and our reorganization. To December 31, 2011, expenses associated with the reorganization amounted to $1.6 million, of which $0.6 million was incurred in 2011. Due to the complex nature of the transaction, costs will continue into 2012.

GENERAL AND ADMINISTRATIVE EXPENSES

($000s, except as noted)	**2011**	2010	Change
General and administrative expenses	**7,422**	7,408	0%
Reorganization costs	**562**	1,073	-48%
Gross general and administrative expenses	**7,984**	8,481	-6%
Less: capitalized and overhead recoveries	**(955)**	(678)	41%
Net general and administrative expenses	**7,029**	7,803	-10%
Per boe ($)	**2.58**	2.81	-8%
As a percentage of gross revenue	**4%**	6%	-33%

Management Fees

The Manager receives a management fee in shares. The issue during 2011 of approximately 1.8 million shares related to the DRIP (2010 – 1.5 million shares) resulted in pro-rata increases in the management fee, in accordance with the management agreement (see Shareholders' Capital).

MANAGEMENT FEES (PAID IN SHARES)

	2011	2010	Change
Shares issued in payment of management fees	**174,117**	169,411	3%
Ascribed value ($000s) (1)	**3,401**	3,016	13%
Per boe ($)	**1.25**	1.09	15%
As a percentage of gross revenue	**2%**	2%	0%
As a percentage of dividends	**3%**	3%	0%

(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

Long-Term Incentive Plan

We are responsible for funding a portion of the long-term incentive compensation plan for employees of the Manager (the 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 2007 LTIP grants vested in 2010 and $1.5 million of share based compensation was paid out in 2010. The 2008 LTIP grants vested in 2011 and $2.3 million of share based compensation was paid out in 2011. A current liability of $3.7 million at December 31, 2011, relates to the 2009 LTIP grants, which vested in January 2012 and were paid out in February 2012.

Deferred Share Unit Plan

Fully-vested deferred share units (DSUs) 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

($000s, except as noted)	**2011**	2010	Change
Gross LTIP	**2,057**	3,780	-46%
Less: capitalized portion	**(308)**	(392)	-21%
Net LTIP	**1,749**	3,388	-48%
Deferred share unit plan	**396**	325	22%
Retirement benefit	**45**	58	-22%
Share based and other compensation	**2,190**	3,771	-42%
Per boe ($)	**0.80**	1.36	-41%
As a percentage of gross revenue	**1%**	3%	-67%

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 2011, the management fee paid was 174,117 shares with an ascribed value of $3.4 million (2010 – 169,411 shares with an ascribed value of $3.0 million).

For the year ended December 31, 2011, the Manager charged Freehold $5.7 million (2010 – $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.

Interest and Financing

In 2012, interest and financing expense declined due to reduced debt levels. The average effective interest rate on advances under our credit facilities during 2011 was 3.3% (2010 – 3.1%).

INTEREST AND FINANCING

($000s, except as noted)	**2011**	2010	Change
Interest on operating line or other	**6**	2	200%
Interest on long-term debt	**2,901**	3,599	-19%
Interest and financing	**2,907**	3,601	-19%
Per boe ($)	**1.07**	1.30	-18%
As a percentage of gross revenue	**2%**	3%	-33%

Depletion and Depreciation

Petroleum and natural gas interests, including the costs of production equipment, future capital costs, estimated asset retirement costs, and directly attributable general and administrative costs, are depleted on the unit-of-production method based on estimated proved plus probable oil and gas reserves (see Accounting Policies and Critical Estimates). Reserves are independently evaluated at year-end. For the first three quarters of 2011, the estimate of proved plus probable reserves was based on the independent evaluation dated December 31, 2010, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as of December 31, 2011. There were no impairments on Freehold's petroleum and natural gas interests for the years ended December 31, 2011 or 2010.

DEPLETION AND DEPRECIATION

($000s, except as noted)	**2011**	2010	Change
Depletion and depreciation	**49,251**	46,132	7%
Per boe ($)	**18.05**	16.60	9%
As a percentage of gross revenue	**31%**	33%	-6%

Income Tax

Up until December 31, 2010, our trust structure was such that both current income tax and deferred tax liabilities were passed on to our unitholders. With our conversion from a trust to a corporation, we became subject to normal corporate tax rates starting in 2011. The corporate income tax rate applicable to 2011 was 26.9%; however, we did not pay any corporate income tax in 2011 (2010 – $nil) due to the tax deductions available to us and the effect of the deferral of our partnership income.

In December 2011, legislation was passed implementing tax measures outlined in the 2011 budget (Bill C-13), which included the elimination of the ability of a corporation to defer income as a result of timing differences in the year-end of the corporation and of any partnership of which it is a member, subject to transitional relief over five years. Freehold's deferred income tax liability includes a partnership deferral that will be reduced over the transitional relief period.

The corporate income tax rate applicable to 2012 is approximately 25%. Taxable income as a corporation is based on total income and expenses (which will vary depending on commodity prices, production volumes, and costs), reduced by claims for both accumulated tax pools and tax pools associated with current year expenditures. As our partnership has a March 31 year-end, we expect to pay no cash income taxes in 2012. However, we expect to have current income tax expense of approximately $21 million, which will be payable in the first quarter of 2013.

The deferred income tax liability on the Consolidated Balance Sheets represents the net difference between the tax values and accounting values (referred to as temporary differences) effected at substantively enacted tax rates expected to apply when the differences reverse. Freehold had a deferred income tax liability of $59.6 million as at December 31, 2011 (December 31, 2010 – $39.1 million). For 2011, Freehold had a deferred income tax expense of $20.5 million (2010 – $6.3 million). Increases in the tax liability and expense for 2011 largely resulted from the deferral of taxes on 2011 income related to our partnership structure. In 2012, these temporary differences will narrow and our non-cash deferred income tax expense will decline as our current tax expense increases.

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)	**2011**	2010	Change
Canadian oil and gas property expense (10% declining balance)	**184,909**	195,932	-6%
Canadian development expense (30% declining balance)	**40,031**	23,980	67%
Canadian exploration expense (100%)	**462**	370	25%
Capital cost allowance (generally 25%)	**13,583**	11,434	19%
Share issue costs	**1,975**	2,962	-33%
Total	**240,960**	234,678	3%

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

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 obligations, DRIP participation, 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

RECONCILIATION OF NET INCOME TO FUNDS FROM OPERATIONS

	2011	2010	Change
Net income	**55,259**	49,349	12%
Adjust for non-cash items:			
Depletion and depreciation	**49,251**	46,132	7%
Share based and other compensation	**(250)**	2,124	-112%
Deferred income tax	**20,470**	6,344	223%
Accretion of asset retirement obligation	**344**	352	-2%
Management fee	**3,401**	3,016	13%
Adjust for cash item:			
Expenditures on reclamation	**(245)**	(346)	-29%
Funds from operations	**128,230**	106,971	20%

Financing Activities

We have a $195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which $48 million was drawn at December 31, 2011. 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 2011. 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 2012. 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 2012. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees.

In 2010, we drew on our credit facilities to fund a $39 million royalty acquisition and in 2011, we drew on our credit facilities to fund a $7.3 million royalty acquisition. From time to time, we paid down our facilities with excess funds from operations.

DEBT ANALYSIS

($000s)	**2011**	2010	Change
Long-term debt	**48,000**	65,000	-26%
Short-term debt (operating line)	**-**	-	-
Total debt	**48,000**	65,000	-26%
Working capital	**(479)**	6,479	-107%
Net debt obligations	**47,521**	71,479	-34%

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, 2011, we were in compliance with all such covenants.

Net debt to annual funds from operations was 0.4 times and net debt was approximately 15% of total capitalization at the end of 2011. Subsequent to year-end, Freehold completed a $49.6 million royalty acquisition and closed a $67.6 million equity financing. As a result, net debt to annual funds from operations is currently approximately 0.2 times and net debt is approximately 8% of total capitalization.

FINANCIAL LEVERAGE AND COVERAGE RATIOS

	2011	2010	Change
Net debt to trailing funds from operations (times)	**0.4**	0.7	-43%
Net debt to dividends (times)	**0.5**	0.7	-29%
Dividends to interest expense (times)	**34.7**	27.2	28%
Net debt to net debt plus equity (%)	**15**	20	-25%

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. At the end of 2011, we had working capital of $0.5 million and higher accounts receivable attributable to higher oil prices. Accounts payable and accrued liabilities at December 31, 2010 included approximately $1.9 million to be refunded upon ruling of an appeal in February 2011 (see Revenue and Other Expense).

COMPONENTS OF WORKING CAPITAL

	2011				2010
($000s)	**December 31**	**September 30**	**June 30**	**March 31**	December 31
Cash	**164**	**188**	**560**	**382**	409
Accounts receivable	**27,634**	**22,064**	**25,067**	**23,565**	22,631
Current assets	**27,798**	**22,252**	**25,627**	**23,947**	23,040
Distributions payable	**(8,560)**	**(8,469)**	**(8,394)**	**(8,335)**	(8,286)
Accounts payable and accrued liabilities	**(14,883)**	**(13,605)**	**(13,436)**	**(16,812)**	(18,760)
Current portion of share based and other compensation	**(3,876)**	**(2,822)**	**(2,988)**	**(3,036)**	(2,473)
Current liabilities	**(27,319)**	**(24,896)**	**(24,818)**	**(28,183)**	(29,519)
Working capital (1)	**479**	**(2,644)**	**809**	**(4,236)**	(6,479)

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

Contractual Obligations and 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 2013 and 2014 based on the principal outstanding at the time the current agreement expires, which is May 2012. As per the terms of the agreement, the first quarterly payment would commence on January 1, 2013.

Freehold has made acquisitions where the agreements include requirements for subsequent payments if the vendor drills additional wells. There is a maximum of $3.2 million of payments to be made no later than December 31, 2013 and a maximum of $0.7 million of payments to be made no later than March 31, 2014.

Shareholders' Capital

In 2011, participation in Freehold's DRIP was approximately 33%, including roughly 16 million shares held by our largest shareholder, CN Pension Trust Funds. We issued 1,785,244 shares (2010 – 1,508,958) related to the DRIP. The ascribed value of $33.5 million (2010 – $25.7 million) was based on the weighted average closing price for the 10 trading days preceding each payment date.

Effective with the May 15, 2011 dividend payment, the DRIP was amended and restated to allow for the issuance of shares from treasury at a 5% discount to market (i.e. 95% of the weighted average closing price for the 10 trading days preceding each payment date). Registered shareholders who wish to enroll in the DRIP may do so by contacting Computershare Trust Company of Canada, the Plan Agent. Beneficial shareholders who wish to participate in the DRIP should contact the broker or other nominee through which their shares are held to obtain appropriate enrollment instructions, ensuring any deadlines or other requirements that such broker or nominee may impose or be subject to are met. U.S. residents may not participate in the DRIP.

As at December 31, 2011, there were 93,551 deferred share units (DSUs) outstanding (2010 – 73,750). During 2011, 12,426 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). On September 1, 2011, the eligible directors were granted 2,178 deferred share units as a pro-rated increase to their annual compensation. On January 1, 2012, the Board granted 17,002 DSUs to eligible directors as part of their annual compensation. As at March 13, 2012, there were 111,995 DSUs outstanding.

During 2011, Freehold issued 174,117 shares (2010 – 169,411 shares) for payment of the management fee (see Related Party Transactions).

On February 29, 2012, we closed an equity offering and issued 3.5 million shares at $20.50 per share for gross proceeds of $70.7 million. Issue costs, including underwriters' fees, were $3.1 million resulting in net proceeds of $67.6 million.

As at December 31, 2011, there were 61,140,673 shares outstanding and as at March 13, 2012, there were 64,862,115 shares outstanding.

SHARES OUTSTANDING

	2011	2010	Change
Weighted average			
Basic	**60,021,736**	58,334,117	3%
Diluted	**60,093,840**	58,389,088	3%
At December 31	**61,140,673**	59,181,312	3%

Dividend Policy

The Board reviews and determines the dividend rate quarterly after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, DRIP participation levels, tax payable, and our capacity to finance operating and investing obligations. The dividend rate is established with the intent of absorbing short-term market volatility over several months. It also recognizes our intention to fund capital expenditures primarily through funds from operations and to maintain a strong balance sheet to take advantage of acquisition opportunities and withstand potential commodity price declines.

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, 2011, our legal stated capital was $287 million (2010 – $250 million).

2011 DIVIDENDS DECLARED

Record Date	Payment Date	Dividend ($ per share)
January 31, 2011	February 15, 2011	0.14
February 28, 2011	March 15, 2011	0.14
March 31, 2011	April 15, 2011	0.14
April 30, 2011	May 16, 2011	0.14
May 31, 2011	June 15, 2011	0.14
June 30, 2011	July 15, 2011	0.14
July 31, 2011	August 15, 2011	0.14
August 31, 2011	September 15, 2011	0.14
September 30, 2011	October 17, 2011	0.14
October 31, 2011	November 15, 2011	0.14
November 30, 2011	December 15, 2011	0.14
December 31, 2011	January 16, 2012	0.14
Total		**1.68**

RECONCILIATION OF DIVIDENDS DECLARED

	2011	2010	Change
Funds from operations	**128,230**	106,971	20%
Capital expenditures	**(25,649)**	(18,054)	42%
Property and royalty acquisitions	**(7,467)**	(38,600)	-81%
Deposit on acquisition	**(5,000)**	-	-
Capital raised by DRIP	**33,490**	25,695	30%
Debt additions (repayment)	**(17,000)**	20,000	-185%
Change in reclamation fund	**2,725**	(464)	-687%
Working capital change	**(8,361)**	2,567	-426%
Dividends declared	**100,968**	98,115	3%

DIVIDENDS PAID (1)

($000s)	**2011**	2010	Change
Dividends paid in cash	**67,204**	72,184	-7%
Dividends paid in shares	**33,490**	25,695	30%
Total dividends paid	**100,694**	97,879	3%

(1) Based on payment date. Dividends were paid on or about the 15th day of the month following the record date.

Dividends declared in 2011 totalled $101.0 million ($1.68 per share). From inception to December 31, 2011, Freehold distributed $994.0 million ($23.89 per share) in dividends to shareholders.

ACCUMULATED DIVIDENDS

	2011	2010	Change
Dividends declared ($000s)			
Accumulated, beginning of year	**893,013**	794,898	12%
Accumulated, end of year	**993,981**	893,013	11%
Dividends per share ($) (1)			
Accumulated, beginning of year	**22.21**	20.53	8%
Accumulated, end of year	**23.89**	22.21	8%

(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.

Since January 1, 2010, we have completed three acquisitions, which were funded through our credit facilities:

- On January 17, 2012, we acquired royalty interests in Alberta, Saskatchewan, and British Columbia for $49.6 million.
- On September 30, 2011, we acquired royalty interests in Alberta for $7.3 million.
- On February 17, 2010, we acquired royalty interests in Alberta, Saskatchewan, and British Columbia for $39 million.

PROPERTY AND ROYALTY ACQUISITIONS

($000s)	**2011**	2010	Change
Purchase price	**8,000**	40,500	-80%
Interest expense	**61**	350	-83%
Evaluation and legal costs	**26**	54	-52%
Purchase price adjustments (1)	**(784)**	(2,747)	-71%
Prior years acquisition adjustments	**164**	443	-63%
Additions to petroleum and natural gas interests	**7,467**	38,600	-81%

(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 2011, development expenditures of $25.6 million amounted to 20% of funds from operations.

We expect to fund capital expenditures from funds from operations and proceeds from the DRIP. 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)	**2011**	2010	Change
Development drilling and other	**19,968**	14,718	36%
Plant and facilities	**5,681**	3,336	70%
Total capital expenditures	**25,649**	18,054	42%
As a percentage of funds from operations	**20%**	17%	18%

We are liable for our share of ongoing environmental obligations and the ultimate reclamation of our working interest properties upon abandonment. At December 31, 2011, the undiscounted value of future environmental and reclamation obligations for the working interest properties was estimated to be $27.1 million. All liabilities settled to the end of 2010 were paid from a cash reclamation fund. At December 31, 2010, the fund had a balance of $2.7 million. In 2011, we discontinued the use of the reclamation fund. Ongoing environmental obligations will be funded from funds from operations.

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.

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 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 2011, our audit staff issued audit exception queries amounting to $4.8 million, bringing the total amount of audit exception queries since 1997 to $49.0 million, of which we have successfully recovered $36.7 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 from operations to debt repayment.

Environmental Regulation and Risk

The oil and 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. 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. For information about climate change and other environmental regulations, see Industry Conditions" in our AIF.

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 14, 2012. 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 in a timely manner.

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;
- 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, 2011, as structured within the COSO Framework. Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2011, 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 2011 that materially affected Freehold's ICFR.

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

International Financial Reporting Standards (IFRS)

This is Freehold's first year of financial reporting under IFRS, which is the new Canadian GAAP for publicly-accountable enterprises. Further details are provided in the following notes to our consolidated financial statements:

- note 1 – basis of presentation
- note 2 – accounting policies
- note 18 – reconciliations to previous Canadian GAAP financial statements

The following discussion explains the significant differences between Freehold's previous Canadian GAAP accounting policies and those applied under IFRS. IFRS policies have been retrospectively applied except where specific IFRS 1 exemptions permit an alternative treatment upon transition.

a. First-time adoption exemptions

IFRS 1 *First-time Adoption of International Financial Reporting Standards* allows first-time adopters' exemptions from retrospective application of certain IFRS.

Deemed cost election for oil and gas assets

Freehold has elected, as at January 1, 2010, that the previous Canadian GAAP net book value of Freehold's petroleum and natural gas interests will be its deemed cost for IFRS. The undeveloped land net book value has been reclassified into an exploration and evaluation asset and the remaining petroleum and natural gas interests balance was prorated to the underlying assets based on proved plus probable reserve values.

Decommissioning liabilities included in oil and gas assets

Freehold has elected, as at January 1, 2010, to re-value the asset retirement obligation in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, using a risk free rate. The corresponding adjustment of $1.3 million has been recorded to the opening deficit.

Business combinations

Freehold has elected, as at January 1, 2010, not to retrospectively apply IFRS 3 *Business Combinations* to any past business combinations.

Share-based payment transactions

Freehold has elected, as at January 1, 2010, not to retrospectively apply IFRS 2 *Share-based Payment* for any previous liabilities arising from cash settled share-based payment transactions.

b. Exploration and evaluation (E&E) assets

Under previous Canadian GAAP, undeveloped land was included in the full cost pool but was excluded when calculating depletion. Under IFRS, E&E costs (undeveloped land) are accounted for in accordance with IFRS 6, Exploration for and Evaluation of Mineral Resources. At January 1, 2010, as part of the IFRS 1 deemed cost election, Freehold classified E&E costs of $27.6 million into a single cost pool, in accordance with IFRS 6.

For the year ended December 31, 2010, E&E costs of $1.4 million were transferred to petroleum and natural gas interests. There were no additions to E&E for the year ended December 31, 2010. All E&E costs are grouped together for impairment testing. There were no impairments relating to E&E assets for the year ended December 31, 2010.

c. Petroleum and natural gas interests

Under previous Canadian GAAP, petroleum and natural gas interests included undeveloped land and both working and royalty interests stated at cost, less accumulated depletion. Under IFRS, petroleum and natural gas interests include both working and royalty interests stated at cost, less accumulated depletion. The significant previous Canadian GAAP and IFRS differences result from the accounting for undeveloped land (IFRS 6), the calculation of depletion (IAS 16) and the assessment of asset impairment (IAS 36).

i. Depletion

Under previous Canadian GAAP, all petroleum and natural gas interests, with the exception of undeveloped land, were depleted on a unit-of-production method based on estimated proved oil and gas reserves. Under IFRS, Freehold has chosen to deplete all petroleum and natural gas interests (not E&E) on the unit-of-production method based on estimated proved plus probable oil and gas reserves.

As a result of the change in reserve basis used in the calculation, for the year ended December 31, 2010, depletion expense decreased $21.3 million with a corresponding increase to petroleum and natural gas interests.

ii. Impairment

Under previous Canadian GAAP, petroleum and natural gas interests impairment testing was performed at the full cost pool or “country” level. For IFRS, impairment testing occurs at a much lower level: the CGU. No impairment existed for the January 1, 2010 transition to IFRS and no impairments existed at December 31, 2010.

d. Asset retirement obligation

Under previous Canadian GAAP, the asset retirement obligation was discounted using a credit adjusted risk free rate and, once recorded, the obligations were not adjusted for future changes in discount rates. For IFRS, under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, Freehold is required to revalue its entire obligation at each reporting date and has elected to use a risk free rate. Depending on the period end rate, there could be significant fluctuations in the asset retirement obligation from period to period.

At January 1, 2010, as part of the IFRS 1 election, Freehold revalued its entire obligation using a rate of 4.1%, which increased the liability by $1.3 million with the offset recorded to the opening deficit.

For the year ended December 31, 2010, using a rate of 3.5% the liability increased $2.4 million with a corresponding offset to the opening deficit of $1.3 million and $1.1 million to petroleum and natural gas interests. For the year ended December 31, 2010, accretion expense decreased $0.1 million.

e. Share based and other compensation

Under previous Canadian GAAP, Freehold recognized a deferred long-term compensation asset, which represented the portion of liability not yet charged to earnings, and accounted for actual forfeitures as they occurred. Under IFRS 2 *Share-based Payment*, Freehold is not able to recognize a deferred long-term compensation asset and is required to include an estimated forfeiture rate in its share based calculation.

For the January 1, 2010 transition, Freehold removed the deferred long-term compensation asset of $2.0 million and recorded an estimated forfeiture adjustment decreasing the opening deficit by $0.1 million. The offset was made to share based and other compensation payable.

For the year ended December 31, 2010, Freehold removed the deferred long-term compensation asset of $2.4 million, recorded an estimated forfeiture adjustment decreasing the opening deficit by $0.1 million and recorded a decrease to the share based and other compensation expense by $0.1 million. The offset was made to share based and other compensation payable.

f. Deferred income tax

Under IFRS, the conceptual foundation for deferred income tax is similar to previous Canadian GAAP, as both use the liability method. Tax rates are applied to temporary differences in carrying amounts of assets and liabilities and then are compared to the value attributed for tax purposes. As Freehold's corporate structure was an open-ended investment trust up until the fourth quarter 2010, IFRS requires a "rate applicable to undistributed profits" be used, which for a trust is the highest marginal individual rate.

For the January 1, 2010 transition, Freehold decreased the deferred income tax liability by $3.0 million with the offset to the opening deficit. In the fourth quarter of 2010, Freehold became a corporation and therefore used a corporate tax rate rather than the highest marginal individual rate, which resulted in a reversal of the remaining portion of the opening balance sheet $3.0 million adjustment. Also as a result of the asset retirement obligation adjustment at January 1, 2010 the deferred income tax liability decreased $0.3 million with the offset to the opening deficit.

For the year ended December 31, 2010, the tax effect relating to the IFRS adjustments was an increase of $8.4 million to deferred income tax expense and a decrease to the opening deficit of $3.3 million. The offset was made to the deferred income tax liability.

g. Deficit

The IFRS transitional adjustments for 2010 that have affected Freehold's deficit are summarized in the following table:

	As at	
($000s)	January 1, 2010	December 31, 2010
Deficit, previous Canadian GAAP	(386,766)	-
Share based and other compensation adjustments	79	218
Depletion and depreciation adjustments	-	21,263
Deferred income tax adjustments	3,373	(5,028)
Asset retirement obligation adjustments	(1,299)	(1,224)
Elimination of deficit adjustment	-	(15,229)
Deficit, IFRS	(384,613)	-

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. Under IFRS, the deficit eliminated at December 31, 2010 decreased by $15.2 million due to the cumulative effects of transitional IFRS adjustments to December 31, 2010.

Recent Pronouncements

As of January 1, 2013, unless otherwise noted, Freehold will be required to adopt the following standards and amendments as issued by the International Accounting Standards Board (IASB). Freehold is assessing the impact of these new requirements and it is expected that they will have no material impact on Freehold's Consolidated Financial Statements other than the potential for additional disclosure.

- IFRS 9, Financial Instruments (January 1, 2015). This is the IASB's first phase of a project to replace IAS 39, Financial Instruments: Recognition and Measurement. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.
- IFRS 10, *Consolidated Financial Statements*, which is to replace Standing Interpretations Committee 12, *Consolidation – Special Purpose Entities* and the consolidation requirements of IAS 27, *Consolidated and Separate Financial Statements*. The new standard eliminates the current risk and rewards approach and establishes control as the single basis for determining the consolidation of an entity.
- IFRS 11, *Joint Arrangements*, which is to replace IAS 31, *Interest in Joint Ventures*. The new standard requires joint operations to be proportionately consolidated and joint ventures to be equity accounted, whereas under IAS 31, joint ventures could be proportionately accounted.
- IFRS 12, *Disclosure of Interests in Other Entities*, which outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity's interests in subsidiaries and joint arrangements.
- IFRS 13, *Fair Value Measurement*, which provides a common definition of fair value, establishes a framework for measuring fair value under IFRS and enhances the disclosures required for fair value measurements.
- IAS 19, *Post Employment Benefits*, which amends the recognition and measurement of defined pension expense and expands disclosures for all employee benefit plans.

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 gas reserve estimation, depletion, impairment of assets, oil and gas revenue accruals, asset retirement obligations, deferred income taxes, and share based and other compensation. 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 Impairment Testing

The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2011. Reserve estimates are updated once a year (as at December 31) and when a significant acquisition or development is completed. At each interim reporting date, reserves are also adjusted for production. 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.

Petroleum and natural gas interests, including the cost of production equipment, future capital costs, estimated asset retirement costs and directly attributable general and administrative costs are depleted on the unit-of-production method based on estimated proved plus probable oil and gas reserves. Reserves are converted to equivalent units on the basis of relative energy content. An increase in estimated proved plus probable oil and gas reserves would result in a corresponding reduction in the depletion rate.

At each reporting date, Freehold assesses groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication of impairment exists, Freehold makes an estimate of its recoverable amount. Where the carrying amount of a group of assets exceeds its recoverable amount, the assets are considered impaired and written down. Impairments can be reversed if the impairment indicators have been reversed. Indicators and recoverable amounts are primarily estimates from independent sources.

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

Freehold measures asset retirement obligation as the present value of management's best estimate of the expenditure required to settle the obligation at the reporting date using a risk-free discount rate. This estimate is recognized when a legal or constructive obligation arises and is recorded as a long-term liability, with a corresponding increase in the carrying value of the petroleum and natural gas working interest asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. At each reporting date, the passage of time and changes to estimates results in liability changes and the amount of accretion is charged against current period income.

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, risk-free 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.

Deferred 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 deferred income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of income tax may be greater than or less than the estimates and the differences may be material.

Share Based and Other Compensation

The LTIP uses a combination of the value of phantom Rife shares and Freehold 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 to shareholders paid by Freehold during the vesting period are assumed to be reinvested in notional rights on the dividend payment date. Since participants in the LTIP receive a cash payment on a fixed vesting date, a liability is determined and recognized as services are rendered based on the fair value of the rights at each period end. The valuation incorporates the consideration of share price, the number of rights outstanding at each period end, an estimated performance multiplier, and an estimated forfeiture rate. Compensation expense is recognized over the vesting period. If factors change actual payments resulting from the LTIP can vary significantly from amounts expensed in prior periods.

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. Period expenses are estimates and actual amounts paid can vary.

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, heavy oil, and natural gas;
- light/heavy oil price differentials;
- changing economic conditions;
- completion of pipeline projects and the timing thereof;
- foreign exchange rates;
- industry drilling, development activity on our royalty lands, our participation in emerging resource plays, and the potential impact of horizontal drilling on production and reserves;
- development of working interest properties;
- participation in the DRIP and our use of cash preserved through the DRIP;
- estimated capital budget and expenditures and the timing thereof;
- long-term debt at year end;
- average production and contribution from royalty lands;
- key operating assumptions;
- acquisition opportunities;
- deferred income tax and our expected taxability and the timing thereof;
- our tax pools and the expected tax horizon;
- our dividend policy;
- treatment under governmental regulatory regimes and tax laws; and
- our assessment of litigation risk.

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 crude 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 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 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 crude oil and natural gas prices;
- future capital expenditure levels;
- future production levels;
- future exchange rates;
- future tax rates;
- future participation rates in the DRIP and use of cash preserved through the DRIP;
- future legislation,
- 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 product successfully to current and new customers;
- our expectation for the consumption of crude oil and natural gas;
- our expectation for industry drilling levels;
- 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.

Key operating assumptions with respect to the forward-looking statements contained in this MD&A are provided in the Outlook section.

You are further cautioned that the preparation of financial statements in accordance with IFRS requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. These estimates may change, having either a positive or negative effect on net income, as further information becomes available and as the economic environment changes.

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 Financial 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 from operations, funds from operations per share, and net debt to funds 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 from operations is a financial term commonly used in the oil and gas industry. It is a key measure of our ability to generate cash, finance operations, and pay monthly dividends. Funds 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 net income or other measures of financial performance calculated in accordance with GAAP. We define funds from operations as net income adjusted for non-cash depletion and depreciation, share based and other compensation, deferred tax expense, accretion of asset retirement obligation, and management fee, and further adjusted for expenditures on reclamation. We consider funds from operations to be a key measure of operating performance as it demonstrates Freehold's ability to generate the necessary funds to fund capital expenditures and repay debt. We believe that such a measure provides a better assessment of Freehold's operations on a continuing basis by eliminating certain non-cash charges. From a business perspective, the most directly comparable measure of funds from operations calculated in accordance with GAAP is net income. Funds from operations per share is calculated based on the weighted average number of shares outstanding consistent with the calculation of net income per share. A reconciliation of funds from operations to net income is provided under Liquidity and Capital Resources – Operating Activities.

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

In addition, we refer to various per boe figures, such as revenues and costs, also considered non-GAAP financial 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 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 barrel). 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. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

MANAGEMENT'S REPORT

The accompanying consolidated financial statements and other financial information in this Financial Report have been prepared by management, who is responsible for their integrity, consistency, objectivity and reliability. To fulfill this responsibility, Freehold maintains policies, procedures and systems of internal control to ensure that reporting practices and accounting and administrative procedures are appropriate to provide reasonable assurance that that assets are safeguarded, transactions are properly authorized, and relevant and reliable financial information is produced.

These consolidated financial statements have been prepared in conformity with International Financial Reporting Standards and, where appropriate, reflect estimates based on management's judgement. The financial information presented throughout this Financial Report is generally consistent with the information contained in the accompanying consolidated financial statements.

Independent 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. 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 consolidated financial statements have been further reviewed and approved by the Board of Directors acting through its Audit Committee, which is comprised of independent directors. The Audit Committee, which meets with the auditors and management to review the activities of each and reports to the Board of Directors, oversees management's responsibilities for the financial reporting and internal control systems. The auditors have full and direct access to the Audit Committee and meet periodically with the committee both with and without management present to discuss their audit and related findings.

William O. Ingram	Darren G. Gunderson
President and Chief Executive Officer	Vice-President, Finance and Chief Financial Officer

March 14, 2012

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Freehold Royalties Ltd.

We have audited the accompanying consolidated financial statements of Freehold Royalties Ltd., which comprise the consolidated balance sheets as at December 31, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of income and comprehensive income, changes in shareholders' equity and cash flows for the years ended December 31, 2011 and December 31, 2010, 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 International Financial Reporting Standards 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 Freehold Royalties Ltd. as at December 31, 2011, December 31, 2010 and January 1, 2010, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 14, 2012

Freehold
ROYALTIES LTD.

CONSOLIDATED BALANCE SHEETS

($000s)	**December 31 2011**	December 31 2010	January 1 2010
		(note 18)	(note 18)
Assets			
Current assets:			
Cash	**$ 164**	$ 409	$ 432
Accounts receivable	**27,634**	22,631	24,056
	27,798	23,040	24,488
Reclamation fund (note 6)	**-**	2,725	2,261
Deposit on acquisition (note 16)	**5,000**	-	-
Exploration and evaluation assets (note 3)	**25,045**	26,251	27,633
Petroleum and natural gas interests (note 4)	**365,597**	375,486	362,204
	$ 423,440	$ 427,502	$ 416,586
Liabilities and Shareholders' Equity			
Current liabilities:			
Dividends payable	**$ 8,560**	$ 8,286	$ 8,050
Accounts payable and accrued liabilities	**14,883**	18,760	17,877
Current portion of share based and other compensation payable (note 9)	**3,876**	2,473	1,643
	27,319	29,519	27,570
Asset retirement obligation (note 6)	**14,282**	9,451	8,459
Share based and other compensation payable (note 9)	**1,289**	3,030	1,669
Long-term debt (note 5)	**48,000**	65,000	45,000
Deferred income tax liability (note 11)	**59,577**	39,107	32,763
Shareholders' equity:			
Shareholders' capital (note 7)	**317,202**	280,311	684,979
Contributed surplus	**1,480**	1,084	759
Deficit	**(45,709)**	-	(384,613)
	272,973	281,395	301,125
	$ 423,440	$ 427,502	$ 416,586

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 AND COMPREHENSIVE INCOME

	Year Ended December 31	
($000s, except per share and weighted average data)	**2011**	2010
		(note 18)
Revenue:		
Royalty income and working interest sales	**$ 157,910**	$ 138,155
Royalty expense and mineral tax	**(4,197)**	(4,092)
	153,713	134,063
Other expense (note 10)	**-**	(1,850)
Expenses:		
Operating	**12,782**	11,569
General and administrative	**7,029**	7,803
Share based and other compensation (note 9)	**2,190**	3,771
Interest and financing	**2,907**	3,601
Depletion and depreciation	**49,251**	46,132
Accretion of asset retirement obligation (note 6)	**344**	352
Management fee (note 8)	**3,401**	3,016
	77,904	76,244
Income before taxes	**75,809**	55,969
Income and capital taxes:		
Income and capital taxes (note 11)	**80**	276
Deferred income tax expense (note 11)	**20,470**	6,344
	20,550	6,620
Net income and comprehensive income	**$ 55,259**	$ 49,349
Net income per share, basic and diluted	**$ 0.92**	$ 0.85
Weighted average number of shares:		
Basic	**60,021,736**	58,334,117
Diluted	**60,093,840**	58,389,088

See accompanying notes to consolidated financial statements.

Freehold
ROYALTIES LTD.

CONSOLIDATED STATEMENTS OF CASH FLOWS

($000s)	Year Ended December 31 2011	2010
		(note 18)
Cash provided by (used in):		
Operating:		
Net income	**$ 55,259**	$ 49,349
Items not involving cash:		
Depletion and depreciation	**49,251**	46,132
Share based and other compensation	**2,190**	3,771
Deferred income tax expense	**20,470**	6,344
Accretion of asset retirement obligation	**344**	352
Shares issued in lieu of management fee	**3,401**	3,016
Expenditures on share based and other compensation	**(2,440)**	(1,647)
Expenditures on reclamation	**(245)**	(346)
Changes in non-cash working capital (note 14)	**(9,860)**	3,722
	118,370	110,693
Financing:		
Long-term debt	**(17,000)**	20,000
Dividends paid	**(67,204)**	(72,184)
	(84,204)	(52,184)
Investing:		
Deposit on acquisition	**(5,000)**	-
Property and royalty acquisitions	**(7,467)**	(38,600)
Capital expenditures	**(25,649)**	(18,054)
Change in reclamation fund	**2,725**	(464)
Changes in non-cash working capital (note 14)	**980**	(1,414)
	(34,411)	(58,532)
Decrease in cash	**(245)**	(23)
Cash, beginning of year	**409**	432
Cash, end of year	**$ 164**	$ 409

See accompanying notes to consolidated financial statements.

Freehold
ROYALTIES LTD.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Year Ended December 31	
($000s)	**2011**	2010
		(note 18)
Shareholders' capital:		
Balance, beginning of year	**$ 280,311**	$ 684,979
Shares issued for dividend reinvestment plan	**33,490**	25,695
Shares issued in lieu of management fee	**3,401**	3,016
Elimination of deficit (note 7)	**-**	(433,379)
Balance, end of year	**317,202**	280,311
Contributed surplus:		
Balance, beginning of year	**1,084**	759
Share based compensation expense	**396**	325
Balance, end of year	**1,480**	1,084
Deficit:		
Balance, beginning of year	**-**	(384,613)
Net income and comprehensive income	**55,259**	49,349
Dividends declared	**(100,968)**	(98,115)
Elimination of deficit (note 7)	**-**	433,379
Balance, end of year	**(45,709)**	-
Total shareholders' equity	**$ 272,973**	$ 281,395

See accompanying notes to consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2011 and 2010

1. Basis of Presentation

Freehold Royalties Ltd. (Freehold) is a dividend-paying corporation incorporated under the laws of the Province of Alberta. Freehold's primary focus is acquiring and managing oil and gas royalties and developing and producing its working interest oil and gas assets.

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.

a. Statement of compliance

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and the interpretations of the International Financial Reporting Interpretations Committee (IFRIC) and adopted by the Canadian Institute of Chartered Accountants (CICA). The CICA recognizes IFRS as the new Canadian GAAP for publicly accountable enterprises. As a result, these consolidated financial statements have been prepared in accordance with IFRS 1 *First-time Adoption of International Financial Reporting Standards*. An explanation of how the transition to IFRS has affected Freehold's reported financial position, financial performance and cash flows is provided in note 18. All affected 2010 numbers in these financial statements and notes have been revised to represent IFRS.

These consolidated financial statements were approved by the Board of Directors on March 14, 2012.

b. Basis of measurement and principles of consolidation

These consolidated financial statements have been prepared on a historical cost basis and include the accounts of Freehold and its wholly-owned subsidiaries; Freehold Resources Ltd. and Freehold Royalties Partnership. All inter-entity transactions have been eliminated.

c. Use of estimates and judgment

The preparation of financial statements in accordance with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, 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 impairment 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.

The asset retirement obligation amounts recorded are based on estimates of inflation rates, risk free rates, timing of abandonments and future abandonment costs, all of which are subject to uncertainty. The long term incentive plan amounts recorded include an estimate of forfeitures and certain management assumptions. The retirement benefit amounts recorded include an estimated discount rate. Actual results could differ as a result of using estimates.

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 deferred income tax liabilities and assets is recognized in income in the period that the change occurs. The actual amount of income tax may be greater than or less than the estimates and the differences may be material.

The determination of a cash generating unit (CGU) and whether an acquisition transaction constitutes a business combination is subject to management judgments. The recoverability of petroleum and natural gas interests and exploration and evaluation assets are assessed at the CGU level. A CGU is the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other CGUs. Each acquisition transaction is reviewed by management and judgment is used when determining if the transaction met the IFRS 3 inputs and processes criteria for business combinations.

d. Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the functional currency of Freehold and its subsidiaries.

2. Significant Accounting Policies

a. Jointly controlled operations and jointly controlled assets

Some of Freehold's oil and gas activities involve jointly controlled assets. These consolidated financial statements include only Freehold's share of the jointly controlled assets and a proportionate share of the relevant revenue and related costs.

b. Exploration and evaluation assets

Exploration and evaluation (E&E) costs, currently undeveloped land, are accounted for in accordance with IFRS 6, *Exploration for and Evaluation of Mineral Resources*. All E&E costs incurred after acquiring the "right to explore" are capitalized into a single cost pool. Upon determination of technical feasibility and commercial viability of reserves, the associated E&E costs are assessed for impairment and the estimated recoverable amount is transferred to petroleum and natural gas interests. All costs incurred prior to acquiring the "right to explore" are expensed as incurred. At each reporting date, E&E costs are reviewed for indicators of impairment. If circumstances indicate the carrying amount exceeds its recoverable amount, the cost is written down to its recoverable amount and the difference is accounted for as an impairment expense. No depletion or depreciation is charged to E&E.

c. Petroleum and natural gas interests

Petroleum and natural gas interests

Petroleum and natural gas interests are classified under IAS 16 as Property, Plant and Equipment and include both working and royalty interests, stated at cost, less accumulated depletion and accumulated impairment losses. All costs incurred after determining technical feasibility and commercial viability of reserves are capitalized. Subsequent expenditure is capitalized only where it enhances the economic benefits of the asset. A gain or loss on disposal of a petroleum and natural gas interest is recognized to the extent that the net proceeds exceed or are less than the appropriate portion of the capitalized costs of the asset.

Depletion

Petroleum and natural gas interests, including the costs of production equipment, future capital costs, estimated asset retirement costs, and directly attributable general and administrative costs, are depleted on the unit-of-production method based on estimated proved plus probable oil and gas reserves. Reserves are converted to equivalent units on the basis of relative energy content.

Impairment

At each reporting date, Freehold assesses groups of assets or CGUs, for impairment whenever events or changes in circumstances indicate that the carrying value of the CGU may not be recoverable. If any such indication of impairment exists, Freehold makes an estimate of its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell (FVLCTS) and its value in use (VIU). Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down. In assessing VIU, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money. FVLCTS is the amount obtainable from the sale of assets in an arm's length transaction less cost of disposal.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the CGU's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the CGU is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depletion, had no impairment loss been recognized for the CGU in prior years. Such reversal is recognized in profit or loss. After such a reversal, the depletion charge is adjusted in future periods to allocate the CGU's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

d. Asset retirement obligation

Freehold measures asset retirement obligation as the present value of management's best estimate of the expenditure required to settle the obligation at the reporting date using a risk-free discount rate. This estimate is recognized when a legal or constructive obligation arises and is recorded as a long-term liability, with a corresponding increase in the carrying value of the petroleum and natural gas working interest asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. At each reporting date, the passage of time and changes to estimates results in liability changes, and the amount of accretion is charged against current period income.

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 deferred income tax liabilities and assets is recognized in income in the period that the change occurs.

f. Share based and other compensation plans

Long term incentive plan

Freehold funds its proportionate share of the costs associated with a long term incentive compensation plan (LTIP) for employees of Rife Resources Ltd., the Manager of Freehold. The LTIP uses a combination of the value of phantom Rife shares and Freehold 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 to shareholders paid by Freehold during the vesting period are assumed to be reinvested in notional rights on the dividend payment date. Since participants in the LTIP receive a cash payment on a fixed vesting date, a liability is determined and recognized as services are rendered based on the fair value of the rights at each period end. The valuation incorporates the consideration of the share price, the number of rights outstanding at each period end, an estimated performance multiplier and an estimated forfeiture rate. Compensation expense is recognized over the vesting period.

Deferred share unit plan

A deferred share unit (DSU) plan was established for the non-management directors of Freehold whereby fully-vested DSUs 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 DSUs for Freehold's common shares, the amount previously recognized in contributed surplus is recorded as an increase to shareholders' capital.

Retirement benefit

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.

g. Net income per share

Basic net income per share is calculated using the weighted average number of shares outstanding for each period. Diluted net income per share is calculated using the weighted average number of diluted shares outstanding for each period. Diluted shares outstanding are calculated assuming 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.

h. 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 properties, to its customers.

i. Financial instruments

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

Cash and short-term investments, if any, are financial assets measured at fair value through profit or loss, and the fair values approximate their carrying value due to their short-term nature. Accounts receivable are classified as loans and receivables and are measured at amortized cost. Accounts payable and accrued liabilities and long-term debt are classified as other financial liabilities and are measured at amortized cost. 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, held-to-maturity or financial liabilities at fair value through profit and loss. Freehold does not have any material embedded derivatives that required separate recognition and measurement.

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.

j. Recent pronouncements

As of January 1, 2013, unless otherwise noted, Freehold will be required to adopt the following standards and amendments as issued by the IASB. Freehold is assessing the impact of these new requirements and it is expected that they will have no material impact on Freehold's Consolidated Financial Statements other than the potential for additional disclosure.

- IFRS 9, *Financial Instruments* (January 1, 2015). This is the IASB's first phase of a project to replace IAS 39*, Financial Instruments*: *Recognition and Measurement*. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.
- IFRS 10, *Consolidated Financial Statements*, which is to replace Standing Interpretations Committee 12, *Consolidation – Special Purpose Entities* and the consolidation requirements of IAS 27, *Consolidated and Separate Financial Statements*. The new standard eliminates the current risk and rewards approach and establishes control as the single basis for determining the consolidation of an entity.
- IFRS 11, *Joint Arrangements*, which is to replace IAS 31, *Interest in Joint Ventures*. The new standard requires joint operations to be proportionately consolidated and joint ventures to be equity accounted, whereas under IAS 31, joint ventures could be proportionately accounted.
- IFRS 12, *Disclosure of Interests in Other Entities*, which outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity's interests in subsidiaries and joint arrangements.
- IFRS 13, *Fair Value Measurement*, which provides a common definition of fair value, establishes a framework for measuring fair value under IFRS and enhances the disclosures required for fair value measurements.
- IAS 19, *Post Employment Benefits*, which amends the recognition and measurement of defined pension expense and expands disclosures for all employee benefit plans.

3. Exploration and Evaluation Assets

($000s)	**December 31 2011**	December 31 2010
Balance, beginning of year	**26,251**	27,633
Additions	**178**	-
Transfers to petroleum and natural gas interests (note 4)	**(1,384)**	(1,382)
Balance, end of year	**25,045**	26,251

There were no impairments for the years ended December 31, 2011 or December 31, 2010.

4. Petroleum and Natural Gas Interests

($000s)	**December 31 2011**	December 31 2010
Cost		
Balance, beginning of year	**421,618**	362,204
Property and royalty acquisitions	**7,467**	38,600
Capital expenditures before capitalized general and administrative expense and LTIP	**24,773**	17,467
Capitalized general and administrative expense and LTIP	**1,006**	979
Transfers from exploration and evaluation assets (note 3)	**1,384**	1,382
Asset retirement obligation additions and revisions (note 6)	**4,732**	986
Balance, end of year	**460,980**	421,618
Accumulated depletion and depreciation		
Balance, beginning of year	**(46,132)**	-
Depletion and depreciation	**(49,251)**	(46,132)
Balance, end of year	**(95,383)**	(46,132)
Net book value, end of year	**365,597**	375,486

The depletion calculation included $10.6 million (2010 – $5.7 million) for estimated future development costs associated with proved plus probable undeveloped reserves.

On September 30, 2011, Freehold closed an acquisition of certain royalty interests in Alberta for $7.3 million, including adjustments. The acquisition was effective July 1, 2011 and was funded through existing credit facilities. In addition, the agreement includes requirements for subsequent payments if the vendor drills additional wells. There is a maximum of $3.2 million of total payments and no payments shall be made after December 31, 2013. A previous acquisition has requirements remaining of $0.7 million to March 31, 2014, if the vendor drills additional wells.

For the year ended December 31, 2011, Freehold capitalized $0.7 million (2010 – $0.6 million) of administrative costs and $0.3 million (2010 – $0.4 million) of long-term incentive plan costs directly related to development activities.

There were no impairments for the years ended December 31, 2011 or December 31, 2010.

5. Long-Term Debt

Freehold has a $195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which $48 million was drawn at December 31, 2011. 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 2011. 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 2012. 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.

Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. At December 31, the fair value of the long-term debt approximated its carrying value, as the long-term debt carries interest at prevailing market rates.

In 2011, the average effective interest rate on advances under Freehold's credit facilities was 3.3% (2010 – 3.1%).

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 $27.1 million (2010 – $22.6 million). Payments to settle the obligations are expected to occur continuously over the next 60 years, with the majority being settled within 10 to 30 years. At December 31, 2011, a risk free rate of 2.5% (2010 – 3.5%) and an inflation rate of 2.0% (2010 – 1.5%) were used to calculate the fair value.

($000s)	**December 31 2011**	December 31 2010
Balance, beginning of year	**9,451**	8,459
Liabilites incurred	**941**	777
Liabilities settled	**(245)**	(346)
Revision in estimates (1)	**3,791**	209
Accretion expense	**344**	352
Balance, end of year	**14,282**	9,451

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

In the first quarter of 2011, Freehold discontinued the use of the reclamation fund.

7. Shareholders' Capital

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

SHARES ISSUED AND OUTSTANDING

	December 31, 2011		December 31, 2010	
	Shares	**Amount ($000s)**	Shares	Amount ($000s)
Balance, beginning of year	**59,181,312**	**280,311**	57,502,943	684,979
Issued for dividend reinvestment plan	**1,785,244**	**33,490**	1,508,958	25,695
Issued in lieu of management fee (note 8)	**174,117**	**3,401**	169,411	3,016
Elimination of deficit in accordance with Reorganization	**-**	**-**	-	(433,379)
Balance, end of year	**61,140,673**	**317,202**	59,181,312	280,311

On December 31, 2010, upon conversion from a Trust to a corporation, 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 $433.4 million, the amount necessary to eliminate the deficit of Freehold outstanding at December 31, 2010.

At December 31, 2011, a balance of 1,945,058 shares was reserved for the dividend reinvestment plan (DRIP), 825,883 shares for the management fee (note 8) and 300,000 shares for the deferred share unit plan (note 9).

As at December 31, 2011, the legal stated capital with respect to Freehold's common shares was $287 million (2010 – $250 million).

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. For the year ended December 31, 2011, Freehold issued 174,117 shares (2010 – 169,411) as a management fee to the Manager pursuant to the management agreement. The ascribed value of $3.4 million (2010 – $3.0 million) was based on the closing price of the shares on the last trading day of each quarter.

For the year ended December 31, 2011, the Manager charged $5.7 million in general and administrative costs (2010 – $5.7 million). At December 31, 2011, there was $0.4 million (2010 – $0.4 million) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was the amount of consideration established and agreed to by both parties.

Expenses relating to compensation for key management personnel, considered to be Freehold's Board of Directors and Senior Management, are as follows:

($000s)	**December 31 2011**	December 31 2010
Short-term benefits (including employee wages and directors fees)	**933**	915
Share based compensation (note 9a and 9b)	**882**	1,185
Post empoyment benefits (note 9c)	**30**	27
Total	**1,845**	2,127

9. Share Based and Other Compensation

a. Long-term incentive plan

Freehold participates in its proportionate share of a long-term incentive compensation plan for all employees of the Manager (the LTIP). The LTIP results in employees receiving cash compensation in relation to the value of a specified number of notional rights after a three-year-vesting period. The 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 share based compensation expense was based on the consideration of the share price, the number of rights outstanding at each period end, an estimated performance multiplier and an estimated forfeiture rate. The 2008 LTIP grants of $2.3 million were paid out in 2011. The total expensed for the year ended December 31, 2011 was $1.7 million (2010 – $3.4 million). For the year ended December 31, 2011, Freehold capitalized $0.3 million (2010 – $0.4 million) of LTIP costs directly related to development activities.

The following table reconciles the change in total accrued share-based incentive compensation:

($000s)	December 31 2011	December 31 2010
Balance, beginning of year	**5,142**	2,907
Increase in liability	**2,057**	3,780
Cash payout	**(2,308)**	(1,545)
Balance, end of year	**4,891**	5,142
Current portion of liability	**3,748**	2,307
Long-term portion of liability	**1,143**	2,835

The following table reconciles the incentive plan activity for the period:

PHANTOM COMMON SHARES

	December 31 2011	December 31 2010
Balance, beginning of year	**242,084**	241,716
Issued	**32,263**	46,191
Dividends re-invested	**18,406**	22,711
Cash payout	**(73,932)**	(68,534)
Balance, end of year	**218,821**	242,084

b. Deferred share unit plan

Fully-vested deferred share units (DSUs) are granted annually to non-management directors. Dividends declared prior to redemption are assumed to be reinvested in notional share units on the dividend payment date. On September 1, 2011, the Board granted 2,178 DSUs to eligible directors as a pro-rated increase to their annual compensation. As at December 31, 2011, there were 93,551 DSUs outstanding (2010 – 73,750), which are redeemable for an equal number of shares any time after the director's retirement.

DEFERRED SHARE UNITS

	December 31 2011	December 31 2010
Balance, beginning of year	**73,750**	53,070
Annual grants	**12,426**	13,916
Additional resulting from dividends	**7,375**	6,764
Balance, end of year	**93,551**	73,750

For the year ended December 31, 2011, Freehold expensed $396,000 (2010 – $325,000) of share based compensation with a corresponding increase to contributed surplus.

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.

For the year ended December 31, 2011, Freehold expensed $45,000 (2010 – $58,000) of other compensation.

($000s)	December 31 2011	December 31 2010
Accrued benefit obligation, beginning of year	**361**	405
Current service cost	**45**	58
Payments	**(132)**	(102)
Accrued benefit obligation, end of year	**274**	361
Current portion of liability	**128**	166
Long-term portion of liability	**146**	195

10. Other Expense

In December 2009, a judgement 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 refunded approximately $1.9 million.

11. Income Tax

Up until December 31, 2010, Freehold's trust structure was such that both current income tax and deferred tax liabilities were passed on to unitholders. With conversion from a trust to a corporation on December 31, 2010, Freehold became subject to normal corporate tax rates starting in 2011. Freehold's 2011 corporate federal and provincial income tax rate was 26.9%; however, Freehold did not pay any corporate income tax in 2011.

In 2011, legislation was passed implementing tax measures outlined in the 2011 budget (Bill C-13), which included an elimination of the ability of a corporation to defer income as a result of timing differences in the year-end of the corporation and of any partnership of which it is a member, subject to transitional relief over five years. Freehold's deferred income tax liability includes a partnership deferral which will be reduced over the period of transitional relief.

Freehold uses the liability method of accounting for income and capital taxes, as described in note 2e. The provision for taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial effective tax rate to Freehold's income before taxes. This difference results from the following items:

	Year Ended December 31	
($000s, except as noted)	**2011**	2010
Income before income taxes	**75,809**	55,969
Combined federal and provincial tax rate (1)	**26.9%**	28.4%
Computed expected income tax expense	**20,393**	15,895
Increase (decrease) in income tax resulting from:		
Non-taxable earnings	**-**	(19,378)
Effect of rate changes	**(845)**	9,724
Capital taxes - current	**80**	276
Capital taxes - deferred	**288**	-
Other	**634**	103
Total income and capital taxes	**20,550**	6,620

(1) The combined tax rate decreased to 26.9% from 28.4% due to the federal rate decreasing from 18% to 16.5% in 2011.

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

	Year Ended December 31	
($000s)	**2011**	2010
Future income tax liabilities:		
Petroleum and natural gas interests	**38,521**	42,252
Deferred tax on partnership income	**24,938**	-
Deferred capital tax	**288**	-
Future income tax assets:		
Asset retirement obligations	**(3,628)**	(2,391)
Share issue expense	**(502)**	(754)
Other	**(40)**	-
Net deferred income tax liability	**59,577**	39,107

Freehold's deferred tax liability primarily relates to the deferral on partnership income and its assets having a higher carrying value relative to the associated tax value. This results in significant taxable temporary differences that reverse over time.

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. Freehold receives 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 operations or capital investment growth opportunities that may offer shareholders better value.

Freehold defines capital as long-term debt, shareholders' equity, and working capital based on the consolidated financial statements. Freehold's capital structure is managed by taking into account operating activities, debt levels, debt covenants, capital expenditures, DRIP participation, dividend levels and taxes; among others. In addition, changes in economic conditions, commodity prices and the risk characteristics of Freehold's assets are considered. Freehold has a declining asset base, therefore ongoing development activities and acquisitions are necessary to replace production and add additional reserves. From time to time, Freehold may issue shares or adjust capital spending to manage current and projected debt levels.

Freehold retains 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. DRIP participation levels can fluctuate significantly on a monthly basis depending on shareholder requirements.

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 that Freehold views as critical in the current environment. Selected forecast information is frequently provided to and approved by the Board of Directors.

Freehold is bound by covenants on its credit facilities. The covenants are monitored as part of management's internal review to ensure compliance with requirements. Under the credit facilities, Freehold is restricted from paying dividends if it is or would be in default under the credit facilities or if borrowings thereunder exceed the borrowing base, currently set at $210 million. As at December 31, 2011, Freehold was in compliance with all such covenants (see note 5).

CAPITALIZATION

	Year Ended December 31	
($000s, except as noted)	**2011**	2010
Shareholders' equity	**272,973**	281,395
Long term debt	**48,000**	65,000
Working capital	**(479)**	6,479
Net debt	**47,521**	71,479
Cash provided by operating activities for last 12 months	**118,370**	110,693
Change in non-cash operating working capital	**9,860**	(3,722)
Trailing 12 months funds from operations (1)	**128,230**	106,971
Net debt to trailing 12 month funds from operations (times)	**0.4**	0.7

(1) Funds from operations, net debt and capitalization as presented are non-GAAP measures and do not have any standardized meaning prescribed by IFRS; and therefore may not be comparable to similar measures of other entities.

13. Financial Instrument Risk Management

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

a. 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 Freehold's receivables. A large part of accounts receivable is with oil and gas industry operators, either as joint venture partners or as payors of various royalty agreements. Freehold's diversified revenue stream limits the size of any one property or industry operator with respect to total receivables.

Freehold maintains an aggressive auditing program to ensure that royalties are paid correctly on production from Freehold's lands in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken. Freehold also audits its working interest properties to ensure that capital costs, operating expenses and production volumes are properly allocated.

The carrying amounts of accounts receivable and cash represent Freehold's maximum credit exposure. Freehold did not have an allowance for doubtful accounts as at December 31, 2011 or 2010 and did not provide for any doubtful accounts and was not required to write off any receivables during the years ended December 31, 2011 or 2010.

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

b. Liquidity risk

Liquidity risk is the risk that Freehold will not be able to meet financial obligations as they come due. Management maintains 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, 2011, there was $162 million of available capacity under the credit facilities. As circumstances warrant, management allocates a portion of funds from operations to debt repayment. Management prepares annual capital expenditure budgets, which are regularly monitored and updated.

c. 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, if any, Freehold selects counterparties based on strong credit ratings and monitors 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

Freehold does 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 years ended December 31, 2011 and 2010, Freehold 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, 2011, would have resulted in a corresponding change to income before taxes of approximately $1.5 million (2010 – $1.4 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 years ended December 31, 2011 and 2010, Freehold 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, 2011, would have resulted in a corresponding change to income before taxes of approximately $1.4 million (2010 – $1.4 million). A $0.25 change (plus or minus) in the AECO natural gas price would have resulted in a corresponding change to income before taxes of approximately $1.3 million (2010 – $1.4 million).

Interest rate risk

Freehold is exposed to interest rate risk on outstanding bank debt, which has a floating interest rate, and fluctuations in interest rates would impact 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, 2011 would have resulted in a corresponding change to income before taxes of approximately $0.5 million (2010 – $0.7 million).

14. Supplemental Disclosure

a. Statements of income and comprehensive income presentation

Freehold's consolidated statements of income and comprehensive income are prepared by nature of expense.

b. Supplemental cash flow disclosure

CHANGES IN NON-CASH WORKING CAPITAL BALANCE

	Year Ended December 31	
($000s)	**2011**	2010
Accounts receivable	**(5,003)**	1,425
Accounts payable and accrued liabilities	**(3,877)**	883
	(8,880)	2,308
Operating	**(9,860)**	3,722
Investing	**980**	(1,414)
	(8,880)	2,308

CASH EXPENSES PAID

	Year Ended December 31	
($000s)	**2011**	2010
Interest	**2,865**	3,625
Taxes	**21**	108

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. Subsequent Events

On January 17, 2012, Freehold closed an acquisition of royalty interests on certain producing and non-producing lands in Alberta, British Columbia and Saskatchewan for $49.6 million before closing adjustments. The acquisition was funded through existing credit facilities and a $5.0 million deposit was paid to the vendor on December 22, 2011.

On February 29, 2012, Freehold closed an equity offering and issued 3,450,000 shares at a price of $20.50 per share for gross proceeds of $70.7 million. The issues costs, including underwriters' fees, were approximately $3.1 million with net proceeds being $67.6 million.

17. Comparative Figures

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

18. Transition to IFRS

As part of the transition to IFRS, Freehold has prepared reconciliations for the Consolidated Balance Sheets at January 1, 2010 and December 31, 2010; the Consolidated Statements of Income and Comprehensive Income for the year ended December 31, 2010; and the Consolidated Statements of Changes in Shareholders' Equity for the year ended December 31, 2010. There were no net impacts to the Statements of Cash Flows. These reconciliations represent the adjustments made to Freehold's previous Canadian GAAP financial statements to comply with IFRS 1. The IFRS accounting policies provided in this note are only those policies that are different from Freehold's previous Canadian GAAP accounting policies. Freehold has chosen accounting policies based on IFRS in effect as at December 31, 2011. A summary of the applicable IFRS 1 exemptions and significant accounting policy changes are discussed following the reconciliations.

CONSOLIDATED BALANCE SHEETS

	As at January 1, 2010			As at December 31, 2010		
($000s)	Previous Canadian GAAP	Effects of Transition to IFRS	IFRS	Previous Canadian GAAP	Effects of Transition to IFRS	IFRS
Assets						
Current assets:						
Cash	432	-	**432**	409	-	**409**
Accounts receivable	24,056	-	**24,056**	22,631	-	**22,631**
	24,488	-	**24,488**	23,040	-	**23,040**
Reclamation fund	2,261	-	**2,261**	2,725	-	**2,725**
Deferred long-term compensation (note 18e)	1,954	(1,954)	**-**	2,381	(2,381)	**-**
Exploration and evaluation assets (note 18b)	-	27,633	**27,633**	-	26,251	**26,251**
Petroleum and natural gas interests (note 18b, c(i), d)	389,837	(27,633)	**362,204**	379,314	(3,828)	**375,486**
	418,540	(1,954)	**416,586**	407,460	20,042	**427,502**
Liabilities and Shareholders' Equity						
Current liabilities:						
Dividends payable	8,050	-	**8,050**	8,286	-	**8,286**
Accounts payable and accrued liabilities	17,877	-	**17,877**	18,760	-	**18,760**
Current portion of share based and other compensation payable (note 18e)	1,643	-	**1,643**	2,473	-	**2,473**
	27,570	-	**27,570**	29,519	-	**29,519**
Asset retirement obligation (note 18d)	7,160	1,299	**8,459**	7,067	2,384	**9,451**
Share based and other compensation payable (note 18e)	3,702	(2,033)	**1,669**	5,629	(2,599)	**3,030**
Long-term debt	45,000	-	**45,000**	65,000	-	**65,000**
Deferred income tax liability (note 18f)	36,136	(3,373)	**32,763**	34,079	5,028	**39,107**
Shareholders' equity:						
Shareholders' capital	684,979	-	**684,979**	265,082	15,229	**280,311**
Contributed surplus	759	-	**759**	1,084	-	**1,084**
Deficit (note 18c(i), d, e, f, g)	(386,766)	2,153	**(384,613)**	-	-	**-**
	298,972	2,153	**301,125**	266,166	15,229	**281,395**
	418,540	(1,954)	**416,586**	407,460	20,042	**427,502**

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

($000s, except per share and weighted average data)	Year Ended December 31, 2010 Previous Canadian GAAP	Effects of Transition to IFRS	IFRS
Revenue:			
Royalty income and working interest sales	138,155	-	**138,155**
Royalty expense and mineral tax	(4,092)	-	**(4,092)**
	134,063	-	**134,063**
Other expense	(1,850)	-	**(1,850)**
Expenses:			
Operating	11,569	-	**11,569**
General and administrative	7,803	-	**7,803**
Share based and other compensation (note 18e)	3,910	(139)	**3,771**
Interest and financing	3,601	-	**3,601**
Depletion and depreciation (note 18c(i))	67,395	(21,263)	**46,132**
Accretion of asset retirement obligation (note 18d)	427	(75)	**352**
Management fee	3,016	-	**3,016**
	97,721	(21,477)	**76,244**
Income before taxes	34,492	21,477	**55,969**
Income and capital taxes:			
Income and capital taxes	276	-	**276**
Deferred income tax expense (reduction) (note 18f)	(2,057)	8,401	**6,344**
	(1,781)	8,401	**6,620**
Net income and comprehensive income	36,273	13,076	**49,349**
Net income per share, basic and diluted	$ 0.62	$ 0.23	**$ 0.85**
Weighted average number of shares:			
Basic	58,334,117	-	**58,334,117**
Diluted	58,389,088	-	**58,389,088**

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Year Ended December 31, 2010		
($000s)	Previous Canadian GAAP	Effects of Transition to IFRS	IFRS
Shareholders' capital			
Balance, beginning of year	684,979	-	**684,979**
Shares issued for dividend reinvestment plan	25,695	-	**25,695**
Shares issued in lieu of management fee	3,016	-	**3,016**
Elimination of deficit (note 18g)	(448,608)	15,229	**(433,379)**
Balance, end of year	265,082	15,229	**280,311**
Contributed surplus			
Balance, beginning of year	759	-	**759**
Share based compensation expense	325	-	**325**
Balance, end of year	1,084	-	**1,084**
Deficit			
Balance, beginning of year (note 18d, e, f)	(386,766)	2,153	**(384,613)**
Net income and comprehensive income (note 18c(i), d, e, f)	36,273	13,076	**49,349**
Dividends declared	(98,115)	-	**(98,115)**
Elimination of deficit (note 18g)	448,608	(15,229)	**433,379**
Balance, end of year	-	-	**-**
Total shareholders' equity	266,166	15,229	**281,395**

The following discussion explains the significant differences between Freehold's previous Canadian GAAP accounting policies and those applied under IFRS. IFRS policies have been retrospectively applied except where specific IFRS 1 exemptions permit an alternative treatment upon transition.

a. First-time adoption exemptions

IFRS 1 *First-time Adoption of International Financial Reporting Standards* allows first-time adopters' exemptions from retrospective application of certain IFRS.

Deemed cost election for oil and gas assets

Freehold has elected, as at January 1, 2010, that the previous Canadian GAAP net book value of Freehold's petroleum and natural gas interests will be its deemed cost for IFRS. The undeveloped land net book value has been reclassified into an exploration and evaluation asset and the remaining petroleum and natural gas interests balance was prorated to the underlying assets based on proved plus probable reserve values.

Decommissioning liabilities included in oil and gas assets

Freehold has elected, as at January 1, 2010, to re-value the asset retirement obligation in accordance with IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, using a risk free rate. The corresponding adjustment of $1.3 million has been recorded to the opening deficit.

Business combinations

Freehold has elected, as at January 1, 2010, not to retrospectively apply IFRS 3 *Business Combinations* to any past business combinations.

Share-based payment transactions

Freehold has elected, as at January 1, 2010, not to retrospectively apply IFRS 2 *Share-based Payment* for any previous liabilities arising from cash settled share-based payment transactions.

b. Exploration and evaluation assets

Under previous Canadian GAAP, undeveloped land was included in the full cost pool but was excluded when calculating depletion. Under IFRS, E&E costs (undeveloped land) are accounted for in accordance with IFRS 6, *Exploration for and Evaluation of Mineral Resources*. At January 1, 2010, as part of the IFRS 1 deemed cost election, Freehold classified E&E costs of $27.6 million into a single cost pool, in accordance with IFRS 6.

For the year ended December 31, 2010, E&E costs of $1.4 million were transferred to petroleum and natural gas interests. There were no additions to E&E for the year ended December 31, 2010. All E&E costs are grouped together for impairment testing. There were no impairments relating to E&E assets for the year ended December 31, 2010.

c. Petroleum and natural gas interests

Under previous Canadian GAAP, petroleum and natural gas interests included undeveloped land and both working and royalty interests stated at cost, less accumulated depletion. Under IFRS, petroleum and natural gas interests include both working and royalty interests stated at cost, less accumulated depletion. The significant previous Canadian GAAP and IFRS differences result from the accounting for undeveloped land (IFRS 6), the calculation of depletion (IAS 16) and the assessment of asset impairment (IAS 36).

i. Depletion

Under previous Canadian GAAP, all petroleum and natural gas interests, with the exception of undeveloped land, were depleted on a unit-of-production method based on estimated proved oil and gas reserves. Under IFRS, Freehold has chosen to deplete all petroleum and natural gas interests (not E&E) on the unit-of-production method based on estimated proved plus probable oil and gas reserves.

As a result of the change in reserve basis used in the calculation, for the year ended December 31, 2010, depletion expense decreased $21.3 million with a corresponding increase to petroleum and natural gas interests.

ii. Impairment

Under previous Canadian GAAP, petroleum and natural gas interests impairment testing was performed at the full cost pool or country level. For IFRS, impairment testing occurs at a much lower level: the CGU. No impairments existed for the January 1, 2010 transition to IFRS and no impairments existed at December 31, 2010.

d. Asset retirement obligation

Under previous Canadian GAAP, the asset retirement obligation was discounted using a credit adjusted risk free rate and, once recorded, the obligations were not adjusted for future changes in discount rates. For IFRS, under IAS 37 *Provisions, Contingent Liabilities and Contingent Assets*, Freehold is required to revalue its entire obligation at each reporting date and has elected to use a risk free rate. Depending on the period end rate, there could be significant fluctuations in the asset retirement obligation from period to period.

At January 1, 2010, as part of the IFRS 1 election, Freehold revalued its entire obligation using a rate of 4.1%, which increased the liability by $1.3 million with the offset recorded to the opening deficit.

For the year ended December 31, 2010, using a rate of 3.5% the liability increased $2.4 million with a corresponding offset to the opening deficit of $1.3 million and $1.1 million to petroleum and natural gas interests. For the year ended December 31, 2010, accretion expense decreased $0.1 million.

e. Share based and other compensation

Under previous Canadian GAAP, Freehold recognized a deferred long-term compensation asset, which represented the portion of liability not yet charged to earnings, and accounted for actual forfeitures as they occurred. Under IFRS 2 *Share-based Payment*, Freehold is not able to recognize a deferred long-term compensation asset and is required to include an estimated forfeiture rate in its share based calculation.

For the January 1, 2010 transition, Freehold removed the deferred long-term compensation asset of $2.0 million and recorded an estimated forfeiture adjustment decreasing the opening deficit by $0.1 million. The offset was made to share based and other compensation payable.

For the year ended December 31, 2010, Freehold removed the deferred long-term compensation asset of $2.4 million, recorded an estimated forfeiture adjustment decreasing the opening deficit by $0.1 million and recorded a decrease to the share based and other compensation expense by $0.1 million. The offset was made to share based and other compensation payable.

f. Deferred income taxes

Under IFRS, the conceptual foundation for deferred income tax is similar to previous Canadian GAAP, as both use the "liability method". Tax rates are applied to temporary differences in carrying amounts of assets and liabilities and then are compared to the value attributed for tax purposes. As Freehold's corporate structure was an open-ended investment trust up until the fourth quarter 2010, IFRS requires a "rate applicable to undistributed profits" be used, which for a trust is the highest marginal individual rate.

For the January 1, 2010 transition, Freehold decreased the deferred income tax liability by $3.0 million with the offset to the opening deficit. In the fourth quarter of 2010, Freehold became a corporation and therefore used a corporate tax rate rather than the highest marginal individual rate, which resulted in a reversal of the remaining portion of the opening balance sheet $3.0 million adjustment. Also as a result of the asset retirement obligation adjustment at January 1, 2010 the deferred income tax liability decreased $0.3 million with the offset to the opening deficit.

For the year ended December 31, 2010, the tax effect relating to the IFRS adjustments was an increase of $8.4 million to deferred income tax expense and a decrease to the opening deficit of $3.3 million. The offset was made to the deferred income tax liability.

g. Deficit

The IFRS transitional adjustments for 2010 that have affected Freehold's deficit are summarized in the following table:

	As at	
($000s)	January 1, 2010	December 31, 2010
Deficit, previous Canadian GAAP	(386,766)	-
Share based and other compensation adjustments	79	218
Depletion and depreciation adjustments	-	21,263
Deferred income tax adjustments	3,373	(5,028)
Asset retirement obligation adjustments	(1,299)	(1,224)
Elimination of deficit adjustment	-	(15,229)
Deficit, IFRS	(384,613)	-

On December 31, 2010, upon conversion from a Trust to a corporation, all outstanding trust units were exchanged for common shares on the basis of one common share for each trust unit held. Under IFRS, the deficit eliminated at December 31, 2010 decreased by $15.2 million due to the cumulative effects of transitional IFRS adjustments to December 31, 2010.

SUPPLEMENTAL INFORMATION

LAND HOLDINGS BY PROVINCE

	Royalty Interest		Working Interest				Total	
	Developed	Undeveloped	Developed		Undeveloped		Developed	Undeveloped
	Gross (1)	Gross (1)	Gross (1)	Net	Gross (1)	Net	Gross (1)	Gross (1)
Alberta	1,342,895	345,174	107,362	16,358	28,005	4,277	1,450,257	373,179
Saskatchewan	298,075	192,778	13,085	4,069	5,300	1,857	311,160	198,078
Ontario	94,297	190,149	-	-	-	-	94,297	190,149
British Columbia	72,230	24,479	20,641	1,285	4,737	79	92,871	29,216
Manitoba	6,136	1,705	159	37	-	-	6,295	1,705
Total	1,813,633	754,285	141,247	21,749	38,042	6,213	1,954,880	792,327

(1) Gross acres are the total number of acres in which we have an interest.

Summary Reserves Data

The reserves data below is presented on a net basis (our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands).

Freehold is unique in that the majority of our assets are royalty interests. However, under National Instrument 51-101, royalty interests cannot be included under gross reserves. This causes our gross reserves to be lower than our net reserves and makes it difficult for investors to compare our reserves to others in our industry.

We believe the most appropriate measure of reserves for Freehold is net reserves.

SUMMARY OF OIL AND GAS RESERVES AS OF DECEMBER 31, 2011 FORECAST PRICES AND COSTS (1)

	Light and Medium Oil		Heavy Oil		Total Crude Oil	
	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)	Net (3)
Reserves Category	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
Proved						
Developed producing	1,554.5	3,334.3	710.1	4,385.0	2,264.5	7,719.2
Developed non-producing	135.6	111.1	128.6	147.7	264.2	258.7
Undeveloped	-	-	-	-	-	-
Total proved	1,690.1	3,445.4	838.7	4,532.6	2,528.8	7,978.0
Probable	1,009.1	1,884.6	665.9	2,840.8	1,675.0	4,725.4
Total proved plus probable	2,699.1	5,330.0	1,504.6	7,373.5	4,203.7	12,703.4

	Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)	Net (3)
Reserves Category	(MMcf)	(MMcf)	(Mbbls)	(Mbbls)	(Mboe)	(Mboe)
Proved						
Developed producing	4,274.1	32,502.1	174.0	796.4	3,150.9	13,932.7
Developed non-producing	64.9	57.8	7.9	5.3	282.9	273.7
Undeveloped	-	-	-	-	-	-
Total proved	4,339.0	32,559.9	181.9	801.7	3,433.8	14,206.3
Probable	3,003.3	17,113.4	127.0	404.7	2,302.6	7,982.4
Total proved plus probable	7,342.3	49,673.3	308.9	1,206.4	5,736.4	22,188.7

(1) Numbers may not add due to rounding.
(2) Gross reserves are our share of working interest properties before deduction of royalties payable to others. Gross reserves exclude royalty interests.
(3) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands.

SUMMARY OF NET PRESENT VALUES
OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS (1)

	Before Income Taxes, Discounted at (% per year)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	826,953	579,313	451,824	375,036	323,705
Developed non-producing	11,181	9,568	8,494	7,699	7,071
Undeveloped	-	-	-	-	-
Total proved	838,134	588,880	460,319	382,735	330,776
Probable	583,373	264,999	161,150	114,742	89,047
Total proved plus probable	1,421,508	853,879	621,469	497,477	419,823

	After Income Taxes, Discounted at (% per year) (2)				
Reserves Category	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved					
Developed producing	677,267	476,367	372,669	310,023	268,044
Developed non-producing	8,265	6,987	6,140	5,516	5,027
Undeveloped	-	-	-	-	-
Total proved	685,533	483,354	378,809	315,539	273,070
Probable	434,266	196,645	119,082	84,418	65,233
Total proved plus probable	1,119,799	679,999	497,891	399,957	338,304

(1) Based on the December 31, 2011 escalated oil and gas price forecasts by an independent qualified reserves evaluator. Future net revenue values do not represent fair market value. Columns may not add due to rounding.
(2) The after-tax net present value calculation reflects the tax burden on the properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying MD&A for additional tax information.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS (1)

	Reserves Category	
($000s)	Proved	**Proved Plus Probable**
Royalty income	722,927	**1,220,554**
Revenue from working interest properties	296,643	**525,604**
Royalty expense on working interest properties	(44,429)	**(81,842)**
Operating costs	(126,985)	**(222,909)**
Development costs	(2,375)	**(10,644)**
Well abandonment and reclamation costs	(7,647)	**(9,255)**
Future net revenue before income taxes	838,134	**1,421,508**
Future income taxes (2)	(152,602)	**(301,709)**
Future net revenue after income taxes (2)	685,533	**1,119,799**

(1) Future net revenue calculation includes future capital expenditures required to bring booked non-producing and undeveloped reserves on production. Future net revenue values do not represent fair market value. Columns may not add due to rounding.
(2) The after-tax net present value calculation reflects the tax burden on the properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying MD&A for additional tax information.

RECONCILIATION OF NET RESERVES (1)
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Light and Medium Oil			Heavy Oil		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2010	3,393	1,835	5,228	4,640	3,240	7,880
Extensions	337	295	632	116	111	227
Improved recovery	-	-	-	-	-	-
Technical revisions	250	(330)	(81)	609	(509)	99
Discoveries	-	-	-	-	-	-
Acquisitions	86	87	173	-	-	-
Dispositions	-	-	-	-	-	-
Economic factors	(7)	(2)	(9)	(1)	(1)	(2)
Production	(614)	-	(614)	(830)	-	(830)
December 31, 2011	**3,445**	**1,885**	**5,330**	**4,533**	**2,841**	**7,373**

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
December 31, 2010	35,496	19,860	55,356	851	445	1,296
Extensions	697	505	1,202	12	14	26
Improved recovery	-	-	-	-	-	-
Technical revisions	2,371	(3,361)	(990)	92	(54)	38
Discoveries	-	-	-	-	-	-
Acquisitions	98	98	197	-	-	1
Dispositions	-	-	-	-	-	-
Economic factors	(11)	12	1	-	-	-
Production	(6,092)	-	(6,092)	(154)	-	(154)
December 31, 2011	**32,560**	**17,113**	**49,673**	**802**	**405**	**1,206**

	Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2010	14,800	8,830	23,629
Extensions	581	504	1,085
Improved recovery	-	-	-
Technical revisions	1,346	(1,454)	(108)
Discoveries	-	-	-
Acquisitions	103	104	207
Dispositions	-	-	-
Economic factors	(10)	(1)	(11)
Production	(2,613)	-	(2,613)
December 31, 2011	**14,206**	**7,982**	**22,189**

(1) Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands. Numbers may not add due to rounding.

FINDING, DEVELOPMENT AND ACQUISITION (FD&A) COSTS (1)

Net Proved Reserves	2011	2010	2009	Three-Year Results
Finding and development expenditures ($000s)	25,649	18,054	15,491	59,194
Change in future development capital estimates ($000s)	1,556	(59)	(295)	1,202
Net reserve additions by development (Mboe)	581	465	615	1,662
Finding and development costs ($/boe)	46.81	38.67	24.70	36.34
Acquisition expenditures ($000s)	7,467	38,600	9,539	55,606
Net reserve additions by acquisition (Mboe)	103	857	211	1,171
Acquisition costs ($/boe)	72.42	45.05	45.14	47.48
Total expenditures ($000s)	33,116	56,654	25,030	114,800
Change in future development capital estimates ($000s)	1,556	(59)	(295)	1,202
Net reserve additions (Mboe)	684	1,322	827	2,833
Finding, development and acquisition costs ($/boe)	50.67	42.81	29.92	40.95

Net Proved Plus Probable Reserves	2011	2010	2009	Three-Year Results
Finding and development expenditures ($000s)	25,649	18,054	15,491	59,194
Change in future development capital estimates ($000s)	4,959	35	1,944	6,938
Net reserve additions by development (Mboe)	1,085	950	1,106	3,141
Finding and development costs ($/boe)	28.20	19.04	15.77	21.05
Acquisition expenditures ($000s)	7,467	38,600	9,539	55,606
Net reserve additions by acquisition (Mboe)	207	1,352	325	1,883
Acquisition costs ($/boe)	36.12	28.56	29.38	29.53
Total expenditures ($000s)	33,116	56,654	25,030	114,800
Change in future development capital estimates ($000s)	4,959	35	1,944	6,938
Net reserve additions (Mboe)	1,292	2,302	1,430	5,024
Finding, development and acquisition costs ($/boe)	29.47	24.63	18.86	24.23

RECYCLE STATISTICS
NET PROVED PLUS PROBABLE RESERVES

($ per boe, except as noted)	2011	2010	2009	Three-Year Results
Operating netback (1) (4)	51.65	44.08	39.61	45.15
Finding, development and acquisition costs (2) (4)	29.47	24.63	18.86	24.23
Recycle ratio (times) (3)	1.8	1.8	2.1	1.9

(1) Total revenue, less operating costs and royalty expenses.
(2) Development expenditures, plus change in future capital, plus acquisition costs; divided by net reserves added through development and acquisition activities.
(3) Operating netback divided by the average cost of acquiring and developing new reserves.
(4) Operating netback is based on gross production, while development and acquisition costs are based on net reserves.

RESERVE LIFE INDEX (1)

	Proved Producing	Total Proved	Proved Plus Probable
Net reserves (Mboe)	13,933	14,206	22,189
Net production (Mboe)	2,103	2,173	2,431
Reserve life index (years)	6.6	6.5	9.1

(1) Reflects the theoretical production life of a property if the remaining reserves were produced out at current rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the estimated production for the following 12 month period (calculated by dividing the Trimble forecast of 2012 net production into the remaining net reserves).

NET ASSET VALUE
AS OF DECEMBER 31, 2011 (1) (2)

($000s, except share data)	December 31 2011	2010	Change
Present value of oil and gas reserves (3) (7)	**621,469**	656,232	-5%
Present value of potash reserves (4) (7)	**31,656**	20,194	57%
Undeveloped land (5)	**91,256**	96,785	-6%
Reclamation fund (6)	**-**	2,725	-100%
Working capital (6)	**479**	(6,479)	-107%
Bank debt (6)	**(48,000)**	(65,000)	-26%
Asset retirement obligation (8)	**(1,511)**	(1,229)	23%
Net asset value	**695,349**	703,228	-1%
Shares outstanding (000s)	**61,141**	59,181	3%
Net asset value per share ($)	**11.37**	11.88	-4%

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

Corporate Information

Board of Directors

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

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

Tullio Cedraschi (3)
Corporate Director

Peter T. Harrison (4)
Manager, Oil and Gas Investments
CN Investment Division

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

P. Michael Maher (1)(2)(3)
Professor, Haskayne
School of Business
University of Calgary

David J. Sandmeyer (4)
Corporate Director

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

(1) Audit Committee
(2) Compensation Committee
(3) Governance and Nominating Committee
(4) Reserves Committee

Officers

D. Nolan Blades
Chair of the Board

William O. Ingram
President and
Chief Executive Officer

Garry W. Bieber
Vice-President, Production

J. Frank George
Vice-President, 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

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

Legal Counsel

Burnet Duckworth & Palmer LLP
Calgary, Alberta

Reserve Evaluators

Trimble Engineering Associates Ltd.
Calgary, Alberta

Stock Exchange and Trading Symbol

Toronto Stock Exchange (TSX)
Common Shares: FRU

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Annual Meeting

Wednesday, May 9, 2012 at 3:30 pm
Sun Life Plaza Conference Centre, Calgary, Alberta

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