being **boring**

2008 annual report

Freehold

ROYALTY TRUST

Inside

Yawn.

All we do is provide predictable, reliable returns to our Unitholders. Another year of solid performance; how dull. Sorry.

Freehold Royalty Trust is one of the largest owners of freehold mineral rights in Canada. We effectively manage our assets to consistently deliver attractive returns to our Unitholders over the long term.

Message to Unitholders

Freehold achieved strong financial results in 2008 with gains in revenue, funds generated from operations, and net income, despite lower commodity prices in the final months of the year. Record high oil prices earlier in the year and the low cost structure of our royalty production combined to deliver strong netbacks and record cash distributions to Unitholders.

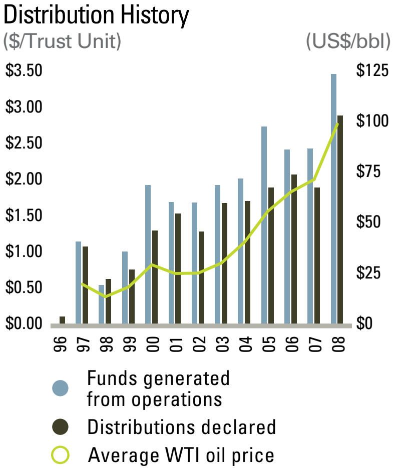
David J. Sandmeyer
President and Chief Executive Officer

Delivering Solid Operational Performance

We're particularly pleased with the success we've had to date on undeveloped mineral title lands we acquired in Southeast Saskatchewan in 2001. Over the past three years we have selectively chosen to participate (that is, take a working interest position) with industry partners to develop these lands, most notably along the Bakken trend. This strategy has been successful in adding value for our Unitholders. The resulting production yields high netbacks; because we hold the mineral title, our share of production is royalty free. Given our large land position spanning most of the Western Canada Sedimentary Basin, there is potential to employ this strategy in other areas in the future.

At December 31, 2008, our land holdings encompassed nearly 2.4 million gross acres. Our undeveloped land was independently valued at $94 million. This represents a 210% increase over the prior year, mainly due to the value attributed to our mineral title lands in Southeast Saskatchewan. The present value of our net proved plus probable oil and gas reserves (discounted at 10%, before tax), was $730.7 million based on the annual, independent evaluation of our reserves. Higher land and reserves values contributed to an 18% increase in net asset value.

Drilling on our royalty lands was down slightly in 2008, although it was still a strong year, with 605 gross wells drilled. Since 1996, operators leasing our royalty lands have drilled 6,800 new wells – at no cost to Freehold. Historically, this 'free drilling' has helped to replace production and reserves. However, as the Basin matures, reserves added per well are declining and that is being reflected in our reserve replacement.



2008 was a record year for oil prices. Freehold in turn paid out record distributions of $2.91 per Trust Unit. We have distributed 82% of funds generated from operations to our Unitholders since inception in 1996.

Our 2008 capital and acquisition program replaced 45% of our production for the year. We spent $13 million on development activities, adding 833,000 boe of net proved plus probable reserves at an average cost of $14.92 per boe. We spent $7.7 million on royalty acquisitions, acquiring 272,000 boe of net proved plus probable reserves at an average cost of $28.25 per boe. These royalty assets have a high value because they are unencumbered by capital or operating costs. Overall, these activities contributed to a three year average recycle ratio of 2.1 times the capital invested.

Weathering the Downturn

While supply and demand fundamentals point to higher prices over the long range, the short-term outlook remains clouded. The continuing deterioration in the economic outlook has reduced current and expected petroleum consumption. The resulting decline in commodity prices has dampened activity levels in western Canada, as lower prices have reduced producers' cash flows and therefore capital expenditure budgets. Industry drilling will be down sharply in 2009 and we expect that will be mirrored on our lands. Commodity prices may face further downward pressure in 2009, especially if demand continues to fall. However, reduced production by Canadian and world producers could allow for some price recovery later in the year.

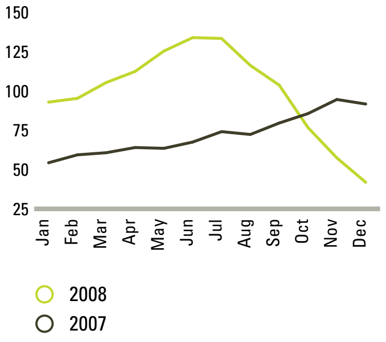
Commodity price and currency rate fluctuations serve to reinforce that our cash flows, and thus our distributions, are largely dependent on cyclical supply and demand factors that are beyond our control. Notwithstanding our exposure to this price volatility, we continue to believe our 'no hedging' policy is the right strategy for Freehold.

The lending capacity of financial institutions has been diminished and risk premiums have increased. Tightening credit markets and a deepening global recession have created turmoil in financial and equity markets, causing significant declines in market valuations throughout the world. Freehold's unit price has largely tracked the decline in oil prices, falling sharply from a high of $24.40 in June 2008 and dipping below $7.00 in February 2009. While current conditions may affect our ability to access financing for potential future acquisitions, we are not reliant on debt or equity markets to finance operating activities.

William O. Ingram
Executive Vice-President and Chief Operating Officer

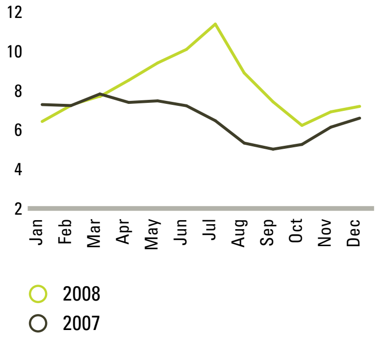
Average WTI Oil Price

(US$/bbl)



Average AECO Natural Gas Price

(Cdn$/Mcf)



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

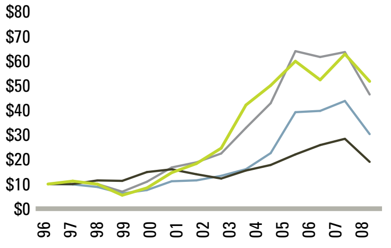
> Commodity prices have exhibited significant volatility over the past two years. Expectations are that we will continue to see lower prices through to the end of 2009. With the benefit of our royalty production, Freehold is in a strong position to ride out this downturn.

On our working interest properties, we will continue to fund development activities from cash provided by operating activities. We anticipate spending approximately $12 million in 2009, primarily to further develop our three major properties in Alberta and Saskatchewan.

We believe some producers may look to sell non-core oil and gas assets during 2009, to fund their core exploration and development programs or reduce debt. This should present opportunities for us to acquire additional royalty interests. Excluding any potential acquisitions, however, we are forecasting average production of 7,500 boe per day for 2009. This is about 5% lower than 2008, as royalty drilling and development activities on our working interest properties will be insufficient to fully offset natural production declines.

In the near term, with the expectation that commodity prices will remain weak, we have lowered our monthly distribution rate to preserve operating stability and financial flexibility through this downturn. Our Board has established a distribution policy for the first half of 2009 of $0.10 per Trust Unit per month based on key operating assumptions outlined on page 40. We will review this policy monthly and make adjustments, if necessary, to ensure that cash distributions are in line with expected cash flow.

Cumulative Value of $10 Investment



Executing a Consistent Strategy

The assets we acquired with the $264 million proceeds of our Initial Public Offering in 1996 have performed very well over the past 12 years, supported by an experienced management team who have managed those assets for more than 25 years. We have augmented our holdings over the years with complementary acquisitions, resulting in an overall asset value of $13.92 per Trust Unit at December 31, 2008. During this period, we have distributed $19.13 per Trust Unit, almost double the IPO price of $10.00.

Since 1996, we have declared $724 million in distributions ($19.13 per Trust Unit). Assuming distributions were reinvested, one $10.00 unit invested in 1996 had a value of $51.70 at the end of 2008.

Looking Ahead to 2011

Freehold, with its large, diversified asset base of primarily royalty interest lands, low risk profile, low sustaining capital requirements, and high payout ratio, is ideally suited to be an income trust. As such, we plan to retain the flow-through advantages of our current structure for as long as is prudent. However, given the federal government's plan to impose a tax on distributions from certain publicly-traded specified investment flow-through (SIFT) entities beginning in 2011, we must assess our options and examine our future strategic direction.

Our Board has formed a special committee of independent directors with a mandate to determine a course of action that best maximizes Unitholder value. This will be an involved process requiring careful due diligence. Among the most important considerations will be commodity price forecasts, the structures that our peers adopt, overall market sentiment, and future access to capital. While draft rules have been issued to facilitate conversion from a trust to a corporation, our current limited ability to generate tax pools makes this alternative a less obvious choice for Freehold than it is for many of the other oil and gas trusts. We anticipate the committee's recommendation by the end of 2009.

Acknowledgments

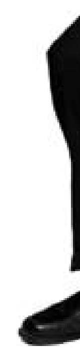
In closing, I would like to acknowledge and thank the employees of Rife Resources (the Manager of the Trust) for their efforts on behalf of Freehold. I would also like to thank my fellow directors for their continued guidance and our Unitholders for their continued support in these turbulent times. In particular, I would like to pay tribute to Bill Siebens and Joe Holowisky.

Bill Siebens, Chairman of Freehold Resources since 1996, plans to step down from the Board and will not stand for re-election in May. Bill has been active in the Canadian petroleum industry since the late 1950s. His knowledge and experience, particularly with respect to the Trust's original royalty assets, have been invaluable to the Board over the past 12 years. We will miss the experience and broad perspective he has added to the Board's strategic decision making.

Joe Holowisky, who retired in January following more than 27 years with Rife, has been a vital member of our management team. As Freehold's Chief Financial Officer since 1996, his contributions have been significant. We have developed a strong audit team that functions effectively to maximize our royalty revenue. We have also built effective internal controls and processes to ensure transparent reporting of financial results. Joe's strong values and distinctive personality will forever be imprinted on the Trust.

To facilitate management succession planning, the Board approved a number of officer appointments during 2008. Bill Ingram, who joined Rife in 1984 and has been Freehold's Vice-President, Production since 1996, was appointed Executive Vice-President and Chief Operating Officer. Darren Gunderson, formerly our Controller, was appointed Vice-President, Finance and Chief Financial Officer; Garry Bieber was appointed Vice-President, Production; and Michael Mogan was appointed Controller.

After 45 years in the oil and gas business, including 27 years with the Manager, I plan to retire in May. The Board plans to appoint Bill Ingram as my successor. At the pleasure of our Unitholders, I hope to remain on the Board. I will step down as President and Chief Executive Officer confident in the knowledge that Freehold is in good health. The Trust has adequate working capital, debt obligations amounting to less than 20% of capitalization, and long-life properties. These quality assets will continue to be effectively managed by motivated, capable personnel who have grown with the Trust and will bring new enthusiasm and new energy to the challenges and opportunities of the future.



David J. Sandmeyer
President and Chief Executive Officer

DJSandmeyer

March 11, 2009

Management Team

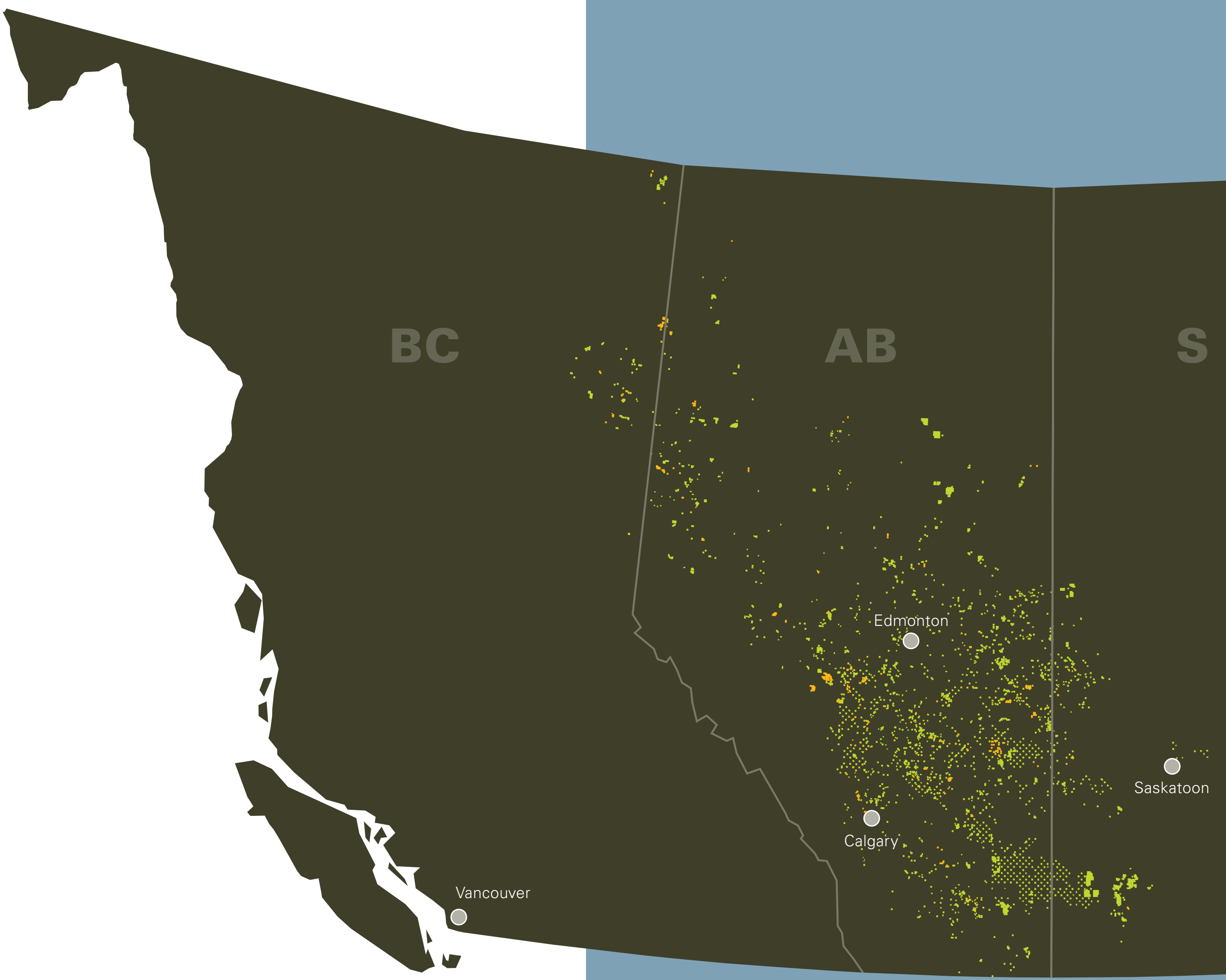
the suits

Standing (left to right):

William Ingram, Executive Vice-President and Chief Operating Officer
David Sandmeyer, President and Chief Executive Officer

Seated (left to right):

Garry Bieber, Vice-President Production
Frank George, Vice-President, Exploitation
Darren Gunderson, Vice-President, Finance and Chief Financial Officer
Michael Okrusko, Vice-President, Land



2008 Land Holdings

Royalty Interests
Working Interests

We have

2.4 million

and interests in

26,000

Land.

(Ho Hum)

gross acres

oil and gas wells

Our Assets

Freehold Royalty Trust is one of the largest owners of mineral title lands in Canada. Our total land holdings of 2.4 million gross acres are geographically widespread throughout western Canada. We have interests in over 26,000 oil and gas wells, and we receive production revenue from about 250 industry partners. This diversified asset base lowers our risk, and our high percentage of royalty income generates strong netbacks.

History of the Royalty Assets Acquired by Freehold in 1996

1973 Hudson's Bay Company sold its interest in 4.6 million acres of mineral title lands to Siebens Oil & Gas Ltd.

1979 Canpar Holdings Ltd. (owned by the CN Pension Trust Funds) and Dome Petroleum Limited jointly acquired the assets of Siebens.

1988 Amoco Canada Petroleum Company Ltd. purchased Dome Petroleum Limited.

1993 Canpar conveyed to Amoco substantially all of Canpar's working interests in exchange for increased mineral title ownership in the producing mineral title lands originally acquired from Siebens.

History of Freehold's Assets

1996 Freehold Royalty Trust was created to acquire all of Canpar's producing royalty interests with Canpar retaining the non-producing deeper rights. At this time Freehold also acquired certain working interests from Rife Resources Ltd. (owned by the CN Pension Trust Funds).

2001 Freehold acquired 129,000 gross acres of producing and undeveloped mineral title and gross overriding royalty (GORR) properties in Southeast Saskatchewan.

2005 Freehold acquired from Canadian Natural Resources Limited, Petrovera Resources, a general partnership owning more than a million gross acres of mineral title and GORR interests throughout western Canada and in southern Ontario. This acquisition doubled our royalty land holdings.

2007 Freehold acquired GORR interests in 319,000 gross acres of land in Alberta and Saskatchewan.

A royalty interest offers the benefit of sharing in production revenue without the operational risks and responsibilities typically associated with oil and gas operations.

Working Interests

99 properties
57% of working interest production from three properties

2008 capital program
$13 million

2009 capital program
$12 million

Freehold owns working interests in 99 properties. Our largest properties are Hayter, Pembina Cardium Unit No. 9, and Southeast Saskatchewan.

In 2009, we will continue to develop Bakken oil-prone title lands in Southeast Saskatchewan following up on successful wells drilled in 2007 and 2008. The operator of Pembina Cardium Unit No. 9, where we have a 10% working interest, is planning a four well pilot program using horizontal drilling, staged fracture stimulation and micro seismic technology. Infill drilling is also anticipated at Hayter.

Reserves and Net Asset Value

Net Oil and Gas Reserves [1, 2]

	Developed Producing	Proved Developed Non-producing	Undeveloped	Total Proved	**Proved Plus Probable**
Light and medium oil (Mbbls)	3,839	52	-	3,891	**5,862**
Heavy oil (Mbbls)	5,311	113	-	5,424	**8,584**
Natural gas (MMcf)	38,132	121	-	38,253	**58,348**
NGL (Mbbls)	815	-	-	816	**1,203**
Total (Mboe)	16,321	185	-	16,506	**25,374**
Reserve life index (years) [3]	6.9			7.0	**9.8**

1 Net reserves are our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands. Columns may not add due to rounding.
2 Evaluated by Trimble Engineering Associates Ltd. effective December 31, 2008.
3 Calculated by dividing the Trimble Engineering Associates Ltd. forecast of 2009 net production into the remaining net reserves.

Net Asset Value [1, 2, 7]

($000s, except as noted)	**2008**	2007	2006
Present value of oil and gas reserves [3, 8]	730,659	711,624	636,267
Present value of potash reserves [4, 8]	27,807	14,317	10,530
Undeveloped land [5]	93,975	30,252	19,412
Reclamation fund [6]	1,827	1,788	2,117
Working capital [6]	(20,055)	11,219	9,050
Bank debt [6]	(140,000)	(178,000)	(100,000)
Asset retirement obligation [6]	(5,663)	(6,608)	(4,598)
Net asset value	688,550	584,592	572,778
Trust Units outstanding (000s)	49,459	49,317	49,174
Net asset value per Trust Unit ($)	**13.92**	**11.85**	**11.65**

1 Non-GAAP measure. Net asset value (NAV) is a measure used widely within the investment community and in the oil and natural gas industry. It shows what is normally referred to as a 'produce-out' NAV calculation under which the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It does not represent a 'going concern' value and it should not be assumed that the present value of oil and gas reserves represent the fair market value of the reserves. Net asset value does not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculations of similar measures for other entities.
2 Columns may not add due to rounding.
3 Based on net proved plus probable reserves evaluated by Trimble, before tax, discounted at 10%.
4 Based on net proved plus probable reserves evaluated by Rife Resources Ltd., before tax, discounted at 10%. Potash reserves are not subject to NI 51-101.
5 Evaluated by Seaton-Jordan & Associates Ltd., effective December 31, 2008.
6 Financial information per Freehold's 2008 consolidated financial statements.
7 Prior periods conform to current presentation.
8 Future net revenue values do not represent fair market value.

Corporate Responsibility

Health, Safety & Environment

We believe it is important to meet the demand for energy in a safe and environmentally responsible manner. Strong safety and environmental performance are fundamental for our long-term growth. We promote a systematic approach to continuous improvement in environmental management and health, safety and social performance.

All of Freehold's properties are operated by other companies. Freehold is a member of the Canadian Association of Petroleum Producers (CAPP). We encourage our operators to participate and excel in the CAPP Stewardship Program by aligning their operations with industry best practices and communicating clearly that meeting or exceeding regulatory requirements is expected.

Freehold's operations are managed by Rife Resources Ltd., a private oil and gas company. Rife and Freehold share a comprehensive Environment, Health & Safety program that includes policies and procedures designed to protect the environment, the health and safety of its employees, contractors and the public. Rife assesses environmental, health and safety liabilities and exposure through pre-acquisition due diligence and regular site assessments and audits. Environmental, health and safety exposures are tracked and addressed with short and long term initiatives. These initiatives include comprehensive training programs for employees and contractors; a contractor management program; engineering and purchasing controls; spill & release control and mitigation; emergency preparedness; hazard and risk assessment; effective communication systems; internal audit and inspection programs; integrity management; and incident investigation.

Rife participates in the Alberta Human Resources and Employment's Partnerships in Health and Safety program, and received a Certificate of Recognition (COR) after completing the required independent safety audit in 2006. Rife will continue to participate in the Partnerships program, which requires internal audits annually and an external audit every three years. Rife has also been awarded "Best Safety Performer" by WorkSafe Alberta for the past three years.

Greenhouse Gas Emissions

Rife participates in the Canadian GHG Challenge Registry, Canada's only voluntary publicly-accessible national registry of greenhouse gas baselines, targets, and reductions. Rife was a Gold Champion Level Reporter in 2008.

Reclamation Fund

Freehold is liable for our share of ongoing environmental obligations and for the ultimate reclamation of working interest properties upon abandonment. We have no reclamation responsibilities on our royalty assets as these are the responsibility of the working interest owners. In 1996, we established a reclamation fund to ensure that required funds are available for future reclamation of working interest wells and facilities once they have reached the end of their economic life.

Community Support

Freehold and Rife support the community by donating to registered charities and not-for-profit organizations. As well, Rife and the employees of Rife, contribute annually to The United Way.

SEEDS Foundation

Freehold's President and CEO, David Sandmeyer, is Chairman of the SEEDS Foundation (Society, Environment, and Energy Development Studies). SEEDS is a national not-for-profit educational organization which develops and provides environmental sustainability and energy education resources to support Canadian educators as they promote student literacy and encourage students to actively take personal and societal responsibility for energy, sustainability, and the environment.

Since the first paper-based version of the Energy Literacy Series was created in 1981, SEEDS has continued to respond to curriculum needs, providing bias-balanced environmental and energy education resources, across Canada, for kindergarten to grade 12 students. They currently deliver nine respected, accredited energy and environmental programs that are developmentally appropriate, curricular supportive, and user friendly. SEEDS estimates that their programs, available to over 14,000 schools and used by 8,000, have reached literally millions of Canadian students and their families during the past 33 years.

We are proud to sponsor this organization. For more information, please visit www.seedsfoundation.ca.

Management's Discussion and Analysis

The following discussion is management's opinion about our consolidated operating and financial results, which include Freehold Resources Ltd., Freehold Royalty Trust and Petrovera Resources (a general partnership) for the year ended December 31, 2008 and previous periods, and the outlook for Freehold based on information available as at March 11, 2009.

The financial information contained herein has been based on information in the consolidated financial statements, which have been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the years ended December 31, 2008 and 2007 and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion and analysis should be read in conjunction with the audited financial statements and notes contained in this annual report. Discussion and analysis of fourth quarter events or items affecting our financial condition, cash flows, and results of operations is contained in our 2008 fourth quarter MD&A, which is incorporated by reference herein. Additional information about us, including our annual information form (AIF), is available on SEDAR at www.sedar.com and on our website at www.freeholdtrust.com.

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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:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs and the related sensitivities of distributions;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs.

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

- volatility in market prices for oil and natural gas;
- currency fluctuations;
- changes in income tax laws or changes in tax laws, regulations, royalties, or incentive programs relating to the oil and gas industry and income trusts;
- uncertainties or imprecision associated with estimating oil and natural gas reserves;
- stock market volatility and our ability to access sufficient capital from internal and external sources;
- a significant or prolonged downturn in general economic conditions or industry activity;
- incorrect assessments of the value of acquisitions;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- geological, technical, drilling, and processing problems;
- environmental risks and liabilities inherent in oil and natural gas operations; and
- other factors discussed under Business Risks and Mitigating Strategies in this MD&A and under Risk Factors and elsewhere in our AIF. Readers are cautioned that the foregoing list of factors is not exhaustive.

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

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

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

The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement and speak only as of the date of this MD&A. Our policy for updating forward-looking statements is to update our key operating assumptions quarterly and, except as required by law, we do not undertake to update any other forward-looking statements.

Conversion of Natural Gas to Barrels of Oil Equivalent (boe)

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

Non-GAAP Measures

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

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

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

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

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

Business Overview

Freehold Royalty Trust is structured as a mutual fund trust under the *Income Tax Act* (Canada). This enables us to return the majority of our income to Unitholders in a tax-effective manner. We receive revenue from oil and natural gas properties as reserves are produced over the economic life of the properties.

We manage one of the largest portfolios of oil and gas royalties in Canada. Our royalty lands are comprised of a large and widely diversified portfolio of properties extending from northeastern British Columbia to southern Ontario. In 2005, we acquired Petrovera Resources, a general partnership, for $351.7 million. The largest transaction in our history, Petrovera added critical mass to enhance stability of our distributions over the long term from royalty interest assets that were a very good fit with our existing portfolio. The acquisition doubled our royalty production and solidified our position as one of the largest holders of oil and gas royalties in Canada. We further augmented our royalty lands in 2007, acquiring gross overriding royalty (GORR) interests in 319,000 gross acres of land in Alberta and Saskatchewan for $90.4 million.

We also we hold working interests in 210,606 gross (25,038 net) acres. The majority of our working interest production comes from three properties in Alberta and Saskatchewan. We have working interests in 96 other properties, which individually contribute less than 100 boe per day.

Mission, Vision and Strategy

Freehold Royalty Trust is pursuing the royalty advantage. We are one of the largest owners of freehold mineral rights in Canada. Our mission is to manage our assets effectively to consistently deliver attractive returns to Unitholders over the long term.

Our vision is to be recognized as the preeminent royalty-focused oil and gas investment in Canada. To achieve our vision we will:

- Actively manage our large portfolio of oil and gas royalty interests by maintaining an aggressive audit program to ensure that royalty income due to the Trust is correctly calculated and collected.
- Successfully develop our working interest properties to sustain production and extend reserve life while maintaining a low risk profile.
- Acquire appropriate assets, with a bias toward royalty interests, to provide long-term growth in the value of the Trust.
- Maintain a conservative approach to debt management to provide maximum financial flexibility with respect to acquisitions and development expenditures while maintaining stable distributions.

The Royalty Advantage

At December 31, 2008, our royalty land holdings encompassed approximately 2.2 million gross acres including 606,122 gross acres of undeveloped land. Our mineral title lands, owned in perpetuity, cover 549,925 gross acres. We have gross overriding royalty interests in approximately 1.6 million acres (including royalty assumption lands).

We have royalty interests in more than 25,000 wells and we receive royalty income from approximately 250 industry operators. Royalty rates vary from less than 1% (for some gross overriding royalties) to 22.5% (for some lessor royalties). This diversity lowers our risk. Royalties offer the benefit of sharing in production revenue without exposure to the capital costs, operating costs, and environmental costs typically associated with oil and gas operations. On the majority of our production, we receive royalty income from gross production revenue (revenue before any royalty expenses and operating costs are deducted). Our high percentage of royalty production (71% in 2008) results in strong netbacks, which maximizes distributions to Unitholders.

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

2008 Netback Analysis

($000s)	Royalty Interest Lands	Working Interest Properties	Total Trust
Gross revenue [1]	141,287	62,829	204,116
Royalty expense and mineral tax [2]	(538)	(6,078)	(6,616)
Net revenue	140,749	56,751	197,500
Operating expense	-	(11,299)	(11,299)
	140,749	45,452	186,201
($ per boe)			
Gross revenue [1]	69.60	76.03	71.46
Royalty expense and mineral tax [2]	(0.27)	(7.36)	(2.32)
Net revenue	69.33	68.67	69.14
Operating expense	-	(13.67)	(3.96)
Operating netback [3]	69.33	55.00	65.18

1 Gross revenue includes potash revenue, sulphur revenue, and other revenue.
2 Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.
3 Operating netback is calculated by subtracting royalty expenses and operating costs from revenues.

Operating Netback

($ per boe)	2008	2007	2006
Royalty interest lands	69.33	47.49	45.81
Working interest properties	55.00	34.90	31.64
Total Trust	65.18	43.54	42.64

Related Party Transactions

We do not operate any of our oil and gas assets, nor do we have any employees. We employ a management company, which gives us better access to resources, including the Manager's knowledgeable and experienced staff, while sharing G&A costs. 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). Rife manages two other private companies that are engaged in similar oil and gas operations. To effectively manage these private companies and the Trust, Rife has assembled a larger, more diversified and more experienced staff than we could otherwise retain to manage our assets. Rife also ensures that the Trust receives priority to consider acquisition opportunities. We believe these organizational and synergistic benefits are advantageous to Unitholders. In addition, the management fees are paid in Trust Units, which we believe aligns the interests of the Manager with the interests of the Unitholders.

The Manager is responsible for the day-to-day management of the business of the Trust subject to the supervisory role of the Board. In particular, the Board makes significant operational decisions and all decisions relating to: (a) issuances of additional securities of the Trust; (b) the acquisition and disposition of properties in excess of $5.0 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities; and (e) the payment of distributions to Unitholders.

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 costs (see General and Administrative Expenses and Unit Based Compensation) and receives a quarterly management fee paid in Trust Units (see Management Fees).

The management agreement has a term of three years and will automatically renew on November 26, 2010, unless terminated. The Manager provides certain administrative and support services to the Trust, including those necessary to:

- Ensure compliance with continuous disclosure obligations under applicable securities legislation.
- Provide investor relations services.
- Provide to Unitholders all information to which Unitholders are entitled under the Trust Indenture.
- Call, hold, and distribute materials including notices of meetings and information circulars in respect of all necessary meetings of Unitholders.
- Determine the amounts payable from time to time to Unitholders and arrange for distributions to Unitholders.
- Determine the timing and terms of future offerings of Trust Units, if any.
- Determine the terms and conditions upon which the Trust may acquire additional royalties.
- Determine the terms and conditions upon which the Trust may from time to time borrow money.

Results of Operations

2008 Highlights

- Gross revenue was 34% higher in 2008 due to exceptionally high commodity prices during the first nine months of the year.
- Net income improved substantially, to $110.0 million ($2.23 per Trust Unit) from a loss of $1.2 million (-$0.02 per Trust Unit) in 2007. The loss in 2007 included a $47.6 million non-cash provision for future income tax following the enactment of the federal government's specified investment flow-through (SIFT) tax legislation.
- Cash provided by operating activities rose 50%, reflecting higher realized prices, partly offset by lower production in 2008.
- Funds generated from operations increased 42%.
- Distributions for 2008 reached a record $2.91 per Trust Unit, more than 50% higher than in 2007, as a result of higher average commodity prices during 2008.
- Production averaged 7,804 boe per day, down 8% as drilling activity and acquisitions during 2008 were insufficient to offset natural production declines.
- Price realizations averaged $69.93 per boe, up 44%.
- Capital expenditures totalled $13.0 million and acquisitions totalled $7.7 million.

Highlights

($000s, except as noted)	2008	2007	2006
Gross revenue	204,116	152,184	143,067
Revenue, net of royalty expenses	197,500	145,921	139,236
Net income (loss)	109,956	(1,192)	45,181
Per Trust Unit, basic and diluted ($)	2.23	(0.02)	0.92
Cash provided by operating activities	179,252	119,641	130,835
Per Trust Unit ($)	3.63	2.43	2.67
Funds generated from operations [1]	171,282	121,008	119,849
Per Trust Unit ($)	3.47	2.46	2.44
Total assets	452,275	504,200	474,228
Long-term debt	140,000	178,000	100,000
Total long-term liabilities	188,417	237,118	108,559
Distributions declared	143,749	94,545	103,100
Per Trust Unit ($) [2]	2.91	1.92	2.10

1 See Non-GAAP Measures.

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

Revenue

We receive revenue from approximately 250 industry operators. Gross revenue of $204.1 million in 2008 was 34% higher than in 2007, as higher commodity prices offset the 8% decline in production volumes. The accompanying table demonstrates the net effect of price and volume variances on gross revenue.

Gross Revenue Variances

($000s)	2008 vs. 2007	2007 vs. 2006
Oil and NGL		
Production increase (decrease)	(13,510)	2,872
Price increase	55,199	7,776
Net increase	41,689	10,648
Natural gas		
Production decrease	(3,738)	(1,028)
Price increase (decrease)	11,473	(486)
Net increase (decrease)	7,735	(1,514)
Other [1]	2,508	(17)
Gross revenue increase	51,932	9,117

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

Net revenue rose 35% in 2008. Royalty expense and mineral tax rose 6%, largely due to higher average commodity prices. Royalty expense is incurred only on our working interest properties.

Net Revenue

($000s)	2008	2007	2006
Gross revenue	204,116	152,184	143,067
Royalty expense and mineral tax [1]	(6,616)	(6,263)	(3,831)
Net revenue	197,500	145,921	139,236

1 Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties and are net of the Alberta Royalty Credit in 2006 (the royalty credit program was discontinued in 2007).

Production

Our production profile for the year was approximately 37% natural gas, 33% heavy oil, 26% light and medium oil, and 4% NGL.

We have no operational control over our royalty lands. As we primarily hold small royalty interests in over 25,000 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.

Production Summary

(boe/d)	2008	2007	2006
Royalty interest lands	5,546	5,825	6,530
Working interest properties	2,258	2,659	1,882
Total	7,804	8,484	8,412

Average Daily Production by Product Type

	2008	2007	2006
Light and medium oil (bbls/d)	2,035	1,925	1,678
Heavy oil (bbls/d)	2,533	3,109	3,187
NGL (bbls/d)	337	333	358
Total oil and NGL (bbls/d)	4,905	5,367	5,223
Natural gas (Mcf/d)	17,399	18,703	19,138
Oil equivalent (boe/d)	7,804	8,484	8,412
Total annual production (Mboe)	2,856	3,097	3,070
Potash (tonnes/d)	11.9	14.2	10.5

Production Reconciliation

(boe/d)	Royalty Interest Lands	Working Interest Properties	Total Trust
2007 average daily production rate	5,825	2,659	8,484
2007 activities, full year impact	808	456	1,264
2008 development	133	208	341
2008 acquisitions	33	2	35
Natural decline	1,253	1,067	2,320
2008 average daily production rate	5,546	2,258	7,804

Product Prices

For the first nine months of 2008, oil prices were substantially higher than last year. The price of West Texas Intermediate (WTI) crude oil reached an all-time high of over US$147 per barrel in July 2008. In the fourth quarter, WTI prices declined 35%, while Edmonton Par declined only 27% because of the 19% decline in the exchange rate between the Canadian and U.S. currencies. The light/heavy oil price differential narrowed significantly, benefitting from higher refinery demand for heavier crude stocks.

Natural gas prices fluctuate according to supply and demand factors within North America, and this was the case in 2008. AECO natural gas prices were 23% higher than last year. However, adequate inventories and lower weather-related demand put downward pressure on natural gas prices through the fourth quarter.

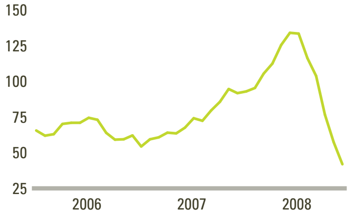
Of particular relevance for Freehold are the markets for heavy oil and prices for the benchmark Bow River Hardisty stream (24.9° API), which is a close proxy for our average oil realizations. The differential between light and heavy oil has a significant impact on our realizations, as approximately 33% of our total boe production is heavy oil.

Average Benchmark Prices [1]

	2008	2007	2006
WTI crude oil (US$/bbl)	99.64	72.31	66.22
US$/Cdn$ exchange rate	0.9428	0.9352	0.8818
Edmonton Par crude oil (Cdn$/bbl)	102.16	76.35	72.77
Light/heavy oil differential (Cdn$/bbl)	17.76	22.83	21.23
Bow River/Hardisty (Cdn$/bbl)	84.40	53.52	51.53
AECO natural gas (Cdn$/Mcf)	8.13	6.61	6.98

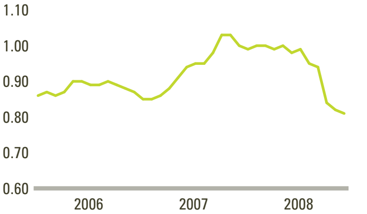
1 Source for commodity prices: Canadian Association of Petroleum Producers.

WTI Oil Prices
monthly average (US$/bbl)



AECO Natural Gas Prices
monthly average (C$/Mcf)

Canadian Dollar Exchange Rate
monthly average (US$)



Freehold's average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average price realizations were 44% higher in 2008 due to higher average commodity prices.

Average Selling Prices

	2008	2007	2006
Oil ($/bbl)	83.45	54.38	50.24
NGL ($/bbl)	67.60	53.53	50.29
Oil and NGL ($/bbl)	82.36	54.33	50.25
Natural gas ($/Mcf)	8.15	6.47	6.54
Oil equivalent ($/boe)	69.93	48.63	46.07
Potash ($/tonne)	613.33	225.28	220.13

Marketing and Hedging

Our royalty lands consist of a large number of properties with generally small volumes per property. A provision of the leases calls for our natural gas to be marketed with the lessees' production. Historically, we have chosen to market our oil production in the same manner. Some of our leases allow us to take our oil production in kind, and we have chosen to do so to speed up receipt of royalty income. As at December 31, 2008, approximately 48% of our royalty oil production was being marketed by Freehold using 30-day contracts.

We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. Approximately 16% of our working interest natural gas production is sold under marketing arrangements tied to the Alberta monthly or daily spot price (AECO) or other indexed referenced prices.

Our production was unhedged in 2008, 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.

Expenses

Royalty Expense and Mineral Tax

Oil and gas producers pay royalties to the owners of mineral rights from whom they hold leases. These are paid to the Crown (provincial and federal government) and freehold mineral title owners. Royalty expense includes all Crown charges (including freehold mineral taxes) and royalty payments to third parties. Crown royalty rates are tied to commodity prices and the level of oil and gas sales. The majority of our mineral tax, payable annually to the Crown, pertains to two sections of land in the Hayter area that were acquired in the Petrovera acquisition in May 2005. Development activity on these lands has resulted in increased production and higher property values. Royalty expense rose 6% year over year due to higher average commodity prices. Royalty expense in 2007 included approximately $250,000 in mineral tax that related to 2006.

Royalty Expense and Mineral Tax [1]

($000s, except as noted)	2008	2007	2006 [4]
Working interest properties			
Crown royalties	4,488	4,258	2,697
Alberta Royalty Credit [2]	-	-	(361)
Third party royalties [3]	1,145	745	807
Mineral tax	445	252	304
Working interest properties	6,078	5,255	3,447
Per boe ($)	7.36	5.41	5.02
Royalty lands			
Crown royalties [5]	-	-	-
Third party royalties [3, 5]	-	-	-
Mineral tax	538	1,008	384
Royalty lands	538	1,008	384
Per boe ($)	0.27	0.47	0.16
Total Trust	6,616	6,263	3,831
Per boe ($)	2.32	2.02	1.25
As a percentage of gross revenue	3%	4%	3%

1 Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties.
2 Effective January 1, 2007, the Alberta Government discontinued the Alberta Royalty Credit.
3 Third party royalties include mineral title and gross overriding royalty payments to third parties.
4 2006 has been restated to conform to the current presentation. Previously, mineral tax on our royalty lands was included in working interests properties, as it was not material.
5 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.

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 excluded from operating costs and accounted for as a reduction to general and administrative (G&A) expenses. A percentage of operating costs is fixed and, as such, per boe operating costs are highly variable to production volumes. On our working interest properties, which accounted for 29% of our production in 2008, operating expenses per boe of production increased 20% because of lower production, higher fuel costs, and continued inflationary pressures. Over the past three years, the energy sector has experienced cost inflation. As 71% of our production was from royalties in 2008, we were somewhat sheltered from the effects of increased costs; royalty production is not encumbered by these expenses.

Operating Expenses

($000s, except as noted)	2008	2007	2006
Working interest properties ($000s)	11,299	11,076	8,309
Per boe ($)	13.67	11.41	12.09
Royalty lands ($000s) [1]	-	-	-
Per boe ($)	-	-	-
Total operating expenses ($000s)	11,299	11,076	8,309
Total Trust ($/boe)	3.96	3.58	2.71
As a percentage of gross revenue	6%	7%	6%

1 We do not incur operating costs on our royalty lands.

General and Administrative Expenses

G&A expenses include direct costs incurred by the Trust and reimbursement of the G&A expenses incurred by the Manager on behalf of the Trust. G&A expenses in 2008 reflect higher staff levels and general inflationary pressures in Calgary, including a tight employment market that has increased compensation for the Manager's staff. We have significant land administration, accounting and auditing requirements to administer and collect royalty payments, including systems to track development activity on the royalty lands. In 2008, we also continued the work of evaluating internal controls; the anticipated cost of the project is expected to reach $500,000, of which $412,000 has been incurred to date.

G&A expenses totalled $6.8 million in 2008, including $5.3 million (2007 – $4.4 million) charged by the Manager for time and direct costs incurred on behalf of the Trust. G&A expenses have remained within 3%-4% of gross revenue for the past three years.

General and Administrative Expenses

($000s, except as noted)	2008	2007	2006
Gross general and administrative expenses	6,877	5,933	5,380
Less overhead recoveries [1]	(87)	(79)	(89)
Net general and administrative expenses	6,790	5,854	5,291
Per boe ($)	2.38	1.89	1.72
As a percentage of gross revenue	3%	4%	4%

1 Our overhead recoveries are minimal because we do not operate any of our royalty production.

Unit Based Compensation

The Trust is responsible for funding a portion of the long-term incentive compensation plan for employees of the Manager (the Manager's LTIP). The liability is estimated at the end of each quarter based on the quarter-end Trust Unit price and performance factors; the related compensation charges are recognized over the three-year vesting period. There was a recovery of unit based compensation in 2008 because of a lower Trust Unit closing price at year-end. At December 31, 2008, we recorded $120,000 (2007 – $697,000) as a deferred long-term compensation asset, representing the portion of the LTIP liability not yet charged to earnings. In addition, we accrued $243,000 (2007 – $1.1 million) as a long-term liability and $83,000 (2007 – $nil) as a current liability. The current liability relates to 2006 LTIP grants, which vested and were paid out in the first quarter of 2009.

Fully-vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. The increase to contributed surplus for the year ended December 31, 2008 was $210,000 (2007 – $265,000), for the non-cash portion of the expenses, and $90,000 was a cash expense for the cancellation of deferred trust units.

Unit Based Compensation

($000s)	2008	2007	2006
Manager's LTIP	(203)	366	43
Deferred trust unit plan	300	265	247
Unit based compensation	97	631	290
Per boe ($)	0.03	0.20	0.09
As a percentage of revenue	0.0%	0.4%	0.2%

Interest Expenses

Interest expense in 2008 was consistent with 2007.

Net Interest Expense

($000s, except as noted)	2008	2007	2006
Interest on operating line or other	31	3	10
Interest on long-term debt	7,008	7,002	5,184
Net interest expense	7,039	7,005	5,194
Per boe ($)	2.46	2.26	1.69
As a percentage of gross revenue	3%	5%	4%

Depletion, Depreciation and Accretion of Asset Retirement Obligation

Oil and gas properties and royalty interests, including the cost of production equipment, future capital costs associated with proved reserves, and the capitalized portion of asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties payable (see Accounting Policies and Critical Estimates). Reserves are independently evaluated every year as at December 31. For the first three quarters of 2008, the estimate of proved reserves was based on the independent evaluation dated December 31, 2007, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2008.

Our ceiling test calculation, performed at December 31, 2008, resulted in no impairment loss. The future prices used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for our quality, transportation, and contract differences.

Depletion, Depreciation and Accretion Expenses

($000s, except as noted)	2008	2007	2006
Depletion and depreciation	67,948	72,400	71,874
Accretion of asset retirement obligation	384	266	257
Total depletion, depreciation and accretion expenses	68,332	72,666	72,131
Per boe ($)	23.92	23.47	23.50
As a percentage of gross revenue	33%	48%	50%

Management Fees

The Manager of the Trust receives a management fee paid quarterly in Trust Units. The ascribed value was 17% higher because of higher quarter-end Trust Unit prices in the first three quarters of 2008.

Management Fees (paid in Trust Units)

	2008	2007	2006
Trust Units issued in payment of management fees	142,616	142,616	142,616
Ascribed value ($000s) [1]	2,482	2,130	2,649
Per boe ($)	0.87	0.69	0.86
As a percentage of revenue	1%	1%	2%
As a percentage of distributions	2%	2%	3%

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

Taxes

Income and Capital Taxes

Freehold Royalty Trust is a taxable trust under the *Income Tax Act* (Canada). We distribute substantially all of our taxable income to Unitholders. By doing so, exposure to current tax at the trust level is eliminated.

Capital taxes consist primarily of the Saskatchewan Capital Tax applied to both taxable capital and gross revenues in that province. Our subsidiary, Freehold Resources Ltd., is a Canadian corporation subject to tax in various jurisdictions. Freehold Resources Ltd. can deduct royalty payments to the Trust in determining its taxable income, and is generally liable for income taxes on its 1% residual interest. Freehold Resources Ltd. is subject to federal and capital tax in any jurisdiction (federal and provincial) in which it has a permanent establishment.

Income and Capital Taxes

($000s)	2008	2007	2006
Provincial capital tax	398	179	253
Current income tax	-	-	38
Total	398	179	291

Tax Pools

We are entitled to claim certain tax deductions available to all owners of oil and gas properties. By using two principal deductions – the Canadian Oil and Gas Property Expense and the Resource Allowance – cash distributions in the Trust's initial years were sheltered from income tax. Over time, because of a general reduction in tax pools available for future claims, an increasing percentage of the annual distributions became taxable. On a consolidated basis the Trust's carrying value for book purposes exceeded the amount available for tax purposes by $244 million at December 31, 2008.

Tax Pools [1]

($000s)	2008	2007	2006
Canadian oil and gas property tax expense	188,957	202,164	133,879
Canadian development expense	16,154	13,507	10,852
Canadian exploration expense	276	131	-
Capital cost allowance	10,887	10,708	10,103
Unit issue costs	2,214	4,427	6,641
Non-capital loss carryovers	-	-	96
Total	218,488	230,937	161,571

1 These amounts, subject to review by Canada Revenue Agency, represent Freehold Royalty Trust's direct tax pools as well as the tax pools of our subsidiary, Freehold Resources Ltd.

Future Income Taxes

The future income tax liability on our Consolidated Balance Sheets as at December 31, 2008, represents the net difference between tax values and accounting values (referred to as temporary differences) effected at substantively enacted tax rates expected to apply when the differences reverse. The SIFT tax is not expected to apply to Freehold until 2011 as a transition period applies to trusts that existed prior to November 1, 2006. However, under Canadian GAAP, the enactment of the SIFT tax legislation requires the recognition of future income tax.

The implementation of the SIFT tax will result in certain of our distributions that would have otherwise been taxed as ordinary income being characterized as dividends in addition to being subject to tax at corporate rates at Freehold's level. Any resultant trust level taxable income will be taxed at a rate that will be approximately equal to corporate income tax rates. The SIFT tax rate is currently 29.5% in 2011 and 28.0% thereafter. There were few tax pools associated with our assets when the Trust was created in 1996 because our property base consisted primarily of royalties. At year-end 2008, we had approximately $218.5 million of available tax pools. In 2011, with our current tax pools, our distributions will become fully taxable at the entity level under the new rules.

On June 9, 2008, changes to the SIFT tax rules were announced, establishing the provincial component of the SIFT tax at provincial corporate tax rates in provinces where the SIFT entity has a permanent establishment rather than using a 13% flat rate as originally legislated. On July 14, 2008, the Department of Finance released draft regulations detailing the formula to be applied in respect of the provincial component of the SIFT tax. Under the proposed rules, we expect the provincial component of the SIFT tax applicable to Freehold will be reduced from 13% to 10%, resulting in a combined SIFT tax rate in 2011 of 26.5%, and 25.0% thereafter. However, as these regulations were not yet substantively enacted for accounting purposes at December 31, 2008, the 13% flat rate remains applicable for financial statement purposes.

Distributions

Because of higher average commodity prices during 2008, distributions reached a record $2.91 per Trust Unit, more than 50% higher than in 2007. Our unhedged production benefited from strong commodity pricing through the first nine months of 2008 and, as a result, we had excess cash from operating activities at the end of 2008. Cash not utilized to pay down debt or fund permitted investments under the terms of our Trust Indenture was distributed to Unitholders in order to minimize direct taxation at the Trust level. Thus, the distribution declared for the month of December (paid on January 15, 2009) included an additional payment of $0.35 per Trust Unit for 2008.

2008 Distributions Declared

Record Date	Payment Date	Distribution ($ per Trust Unit)
January 31, 2008	February 15, 2008	0.15
February 28, 2008	March 15, 2008	0.15
March 31, 2008	April 15, 2008	0.15
April 30, 2008	May 15, 2008	0.18
May 31, 2008	June 15, 2008	0.18
June 30, 2008	July 15, 2008	0.25
July 31, 2008	August 15, 2008	0.25
August 31, 2008	September 15, 2008	0.25
September 30, 2008	October 15, 2008	0.25
October 31, 2008	November 15, 2008	0.25
November 30, 2008	December 15, 2008	0.25
December 31, 2008	January 15, 2009	0.60 [1]
Total		2.91

1 Includes an additional $0.35 representing increased income in 2008.

Significantly lower commodity prices have resulted in lower monthly distributions to date in 2009. On January 20, the Board announced a distribution policy for the first quarter of 2009 at $0.10 per Trust Unit per month.

From inception to December 31, 2008, the Trust has distributed $724 million ($19.13 per Trust Unit) to Unitholders.

Accumulated Distributions

	2008	2007	2006
Distributions to Unitholders ($000s)			
Accumulated, beginning of year	580,669	486,124	383,024
Accumulated, end of year	724,418	580,669	486,124
Distributions per Trust Unit ($) [1]			
Accumulated, beginning of year	16.22	14.30	12.20
Accumulated, end of year	19.13	16.22	14.30

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

Unitholder Taxation

For purposes of the *Income Tax Act* (Canada), Freehold Royalty Trust is treated as a mutual fund trust. Each year, we file a T3 income tax return with the taxable income allocated to and made taxable in the hands of Unitholders. This taxable income is allocated, on T3 supplementary forms, to each Unitholder who was entitled to distributions for the year. The T3 slip will report the taxable portion of the distribution in Box 26 and the return of capital portion in Box 42. Unitholders reduce the adjusted cost base (ACB) of their Trust Units by an amount equal to the portion of the distribution received in the form of return of capital. For Canadian tax purposes, 96% of distributions declared in 2008 were taxable as income, unless held in a registered plan. Additional tax information is available on our website.

Liquidity and Capital Resources

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

Operating Activities

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

($000s, except as noted)	2008	2007	2006
Cash provided by operating activities	179,252	119,641	130,835
Increase (decrease) in non-cash working capital	(7,970)	1,367	(10,986)
Funds generated from operations	171,282	121,008	119,849
Per Trust Unit ($)	3.47	2.46	2.44

The following table illustrates the relationship between cash provided from operating activities and historical distributions, as well as net income and historical distributions. The Trust has historically distributed less cash than cash provided by operating activities. This excess cash has been used to fund capital expenditures and repay bank debt as required. Net income includes significant non-cash charges that do not affect cash flow. These charges amounted to $61.9 million in 2008 (2007 – $123.0 million). Net earnings also include fluctuations in future income taxes due to changes in tax rates and tax rules. In addition, other non-cash charges, such as depletion and depreciation on petroleum and natural gas interests and accretion on the asset retirement obligation, do not represent the actual cost of maintaining our productive capacity given the natural declines associated with oil and gas assets. In these instances, where distributions exceed net earnings, a portion of the cash distribution paid to Unitholders may represent an economic return of the Unitholders' capital.

Distribution Analysis

($000s, except as noted)	2008	2007	2006
Cash provided by operating activities	179,252	119,641	130,835
Net income (loss)	109,956	(1,192)	45,181
Cash distributions paid or payable	143,749	94,545	103,100
Excess of cash provided by operating activities over cash distributions	25%	27%	27%
Shortfall of net income over cash distributions	-24%	-101%	-56%

Financing Activities

We have a $195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks and a $15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 100 to 170 basis points, and standby fees. The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. At December 31, 2008, we had no short-term debt outstanding and long-term debt was $140 million. We had $70 million of available capacity under our credit facilities, but some of this capacity was used to pay December's distribution paid on January 15, 2009. The effect of December's distribution payable is shown in our negative working capital of $20.1 million and net debt of $160.1 million.

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 making distributions 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, 2008, the Trust was in compliance with all such covenants. Freehold's borrowing base is dependent on our lenders' annual review and interpretation of our reserves and future commodity prices, with the next renewal to occur by May 2009.

Debt Analysis

($000s)	2008	2007	2006
Long-term debt	140,000	178,000	100,000
Short-term debt (operating line)	-	-	-
Total debt	140,000	178,000	100,000
Less: working capital	(20,055)	11,219	9,050
Net debt obligations	160,055	166,781	90,950

At December 31, 2008, our ratio of net debt (total debt adjusted for working capital) to trailing funds generated from operations was 0.9 to 1. The year-over-year improvement results from higher cash flows in 2008 due to higher commodity pricing in the first nine months of the year.

Financial Leverage and Coverage Ratios

($000s)	2008	2007	2006
Net debt to trailing funds generated from operations (times)	0.9	1.4	0.8
Net debt to distributions (times)	1.1	1.8	0.9
Distributions to interest expense (times)	20.4	13.5	19.8
Net debt to net debt plus equity (%)	42	40	21

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 year-end 2008, we had negative working capital of $20.1 million. Current liabilities increased (mainly due to the additional distribution of $0.35 per Trust Unit declared in December and payable on January 15, 2009), while current assets decreased (mainly due to the lower dollar value of accounts receivable because of the decline in commodity prices during the fourth quarter).

Components of Working Capital

($000s)	Dec. 31 2008	Sept. 30 2008	June 30 2008	Mar. 31 2008	Dec. 31 2007
Cash	537	212	521	617	393
Current portion of deferred compensation	-	38	194	106	-
Accounts receivable	23,261	38,507	42,538	35,131	26,802
Current assets	23,798	38,757	43,253	35,854	27,195
Distributions declared	(29,676)	(12,356)	(12,347)	(7,403)	(7,398)
Current portion of unit based compensation	(83)	(452)	(1,166)	(423)	-
Accounts payable and accrued liabilities	(14,094)	(14,830)	(11,708)	(11,433)	(8,578)
Current liabilities	(43,853)	(27,638)	(25,221)	(19,259)	(15,976)
Working capital	(20,055)	11,119	18,032	16,595	11,219

Commitments

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 have to be made in 2010 and 2011 based on the principal outstanding at the time the current agreement expires, which is May 2009. As per the terms of the agreement, the first quarterly payment would commence on January 1, 2010.

Unitholders' Capital

As at December 31, 2008 and March 11, 2009, there were 49,459,429 Trust Units outstanding. Our Trust Indenture provides that not more than 49% of the Trust's Units can be held by non-residents of Canada. We monitor foreign ownership levels on a regular basis through declarations from Unitholders and geographical searches. Accordingly, the reported level of Canadian ownership is subject to these limitations, and the level of Canadian ownership can change at any time without notice.

At the Annual and Special Meeting of Unitholders held on May 10, 2006, Unitholders approved a deferred trust unit plan for non-management directors whereby fully vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. Deferred trust units are redeemable for an equal number of Trust Units any time after the director's retirement.

On January 1, 2008, the Board approved annual grants for 2008 totalling 11,538 deferred trust units, allocating 1,923 to each eligible director and 3,846 to the Chair of the Board. In addition, the Board approved the grant of 1,002 deferred trust units to Tullio Cedraschi upon his election as an independent director on May 7, 2008. Prior thereto, he was a nominee of the Manager and not eligible to receive grants. As at December 31, 2008, there were 44,087 deferred trust units outstanding. On January 1, 2009, the Board approved annual grants for 2009 totalling 20,020 deferred trust units, allocating 2,860 to each eligible director and 5,720 to the Chair of the Board. At March 11, 2009, there were 67,488 deferred trust units outstanding.

Trust Units Outstanding

	2008	2007	2006
Weighted average			
Basic	49,370,878	49,228,411	49,085,795
Diluted	49,412,670	49,228,411	49,093,609
At December 31	49,459,429	49,316,813	49,174,197

New SIFT Tax Legislation

The new SIFT tax is expected to result in adverse tax consequences to Freehold and certain Unitholders (including Unitholders that are tax deferred or non-residents of Canada) and may impact Freehold's cash distributions starting in 2011. The after tax impact for Canadian resident individuals who hold Freehold Trust Units outside a tax-deferred plan is mitigated by the federal and provincial enhanced dividend tax credit mechanism that will apply in 2011 and future years.

The SIFT tax may reduce the value of our Trust Units, which would be expected to increase our cost of raising capital in the public capital markets. In addition, the tax changes are expected to substantially eliminate the competitive advantage that Freehold and other Canadian trusts enjoy relative to their corporate peers in raising capital in a tax-efficient manner and place Freehold and other Canadian trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. The tax changes are also expected to make our Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for Freehold to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize Freehold's legal and tax structure to mitigate the expected impact of the tax changes.

Further, the tax changes provide that, while there is no intention to prevent "normal growth" during the transitional period, any "undue expansion" could result in the transition period being "revisited", presumably with the loss of the benefit to us of that transitional period. As a result, the adverse tax consequences resulting from the tax changes could be realized sooner than January 1, 2011.

On December 15, 2006, the Department of Finance issued guidelines with respect to what is meant by normal growth in this context. Normal growth would include equity growth within certain "safe harbour" limits, measured by reference to market capitalization as of the end of trading on October 31, 2006. Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% in each of the following three years. Moreover, the yearly limits are cumulative, so that any unused limit for a period carries over to the subsequent period. On December 4, 2008, the federal government proposed revisions to these guidelines to accelerate the safe harbour amount, permitting a SIFT entity to immediately issue new equity to bring its cumulative growth up to 100% of its October 31, 2006 market capitalization. Our market capitalization as of the close of trading on October 31, 2006 was approximately $929 million. We have not issued any equity since the SIFT tax announcement in 2006.

We do not anticipate that the normal growth guidelines will impair our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transitional period. However, they could adversely affect the cost of raising capital and our ability to undertake significant acquisitions.

Tightening credit markets and a deepening global recession have created turmoil in financial and equity markets, causing significant declines in market valuations throughout the world. Freehold's unit price has largely tracked the decline in oil prices, falling sharply from a high of $24.40 in June 2008 and dipping below $7.00 in February 2009 – a level we have not seen since 2000.

Investing Activities

Acquisitions

Our strategy is to acquire appropriate assets, with a bias toward royalty interests, to provide long-term growth in the value of the Trust. The key acquisition criteria are:

- Quality assets: producing properties with an established production history and low reserve risk;
- Attractive returns: a forecast internal rate of return that is 400 basis points above long-term (ten year) Government of Canada bonds;
- Reasonable assumptions: commodity price and exchange rate assumptions from an independent engineering firm acceptable to the Board;
- High operating netbacks; and
- Long economic life: an expected economic life of not less than ten years.

On July 7, 2008, we acquired certain royalty and minor working interests in Alberta for $8.5 million. On August 31, 2007, we acquired gross overriding royalty (GORR) interests on 309,800 gross acres of land in Alberta and Saskatchewan for $57.6 million. On September 5, 2007, we acquired a 7% GORR interest on 9,078 gross acres of land at Dixonville, Alberta, for $32.8 million. These acquisitions were funded through our credit facilities. We continue to pursue opportunities to augment our production and reserves, primarily targeting royalty interests, while maintaining a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future Unitholders.

Property and Royalty Acquisitions

($000s)	2008	2007	2006
Purchase price	8,475	93,700	5,500
Interest expense	-	1,745	-
Evaluation and legal costs	-	405	-
Purchase price adjustments [1]	-	(5,394)	(118)
Prior year acquisition adjustments	(782)	-	-
Additions to petroleum and natural gas interests	7,693	90,456	5,382

1 Net revenue from effective date to closing.

Capital Expenditures

Our capital expenditure obligations (with respect to our working interest properties) are deducted from funds generated from operations prior to the determination of distributions to Unitholders. The amount of expenditures to be deducted is limited to 15% of annual funds generated from operations. As we do not incur development expenditures on our royalty lands, our capital requirements are modest, relative to most energy trusts. In 2008, development expenditures of $13 million amounted to 8% of funds generated from operations.

We expect to fund distributions and capital expenditures from cash provided by operating activities. However, we will continue to fund acquisitions and growth through additional debt and equity. In the oil and gas sector, because of the nature of reserve reporting, natural reservoir declines, 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)	2008	2007	2006
Development drilling	10,349	8,526	7,584
Plant and facilities	2,643	3,641	3,862
Total capital expenditures	12,992	12,167	11,446
As a percentage of funds generated from operations	7.6%	10.1%	9.6%

Reclamation Fund

We are liable for our share of ongoing environmental obligations and the ultimate reclamation of our working interest properties upon abandonment. We have no reclamation responsibilities on our royalty assets, as these are the responsibility of the working interest owners. Ongoing environmental obligations are funded from funds generated from operations. At December 31, 2008, our estimated undiscounted share of future environmental and reclamation obligations for the working interest properties is approximately $17.3 million.

In 1996, we established a reclamation fund to ensure that required funds are available for future reclamation of working interest wells and facilities once they have reached the end of their economic lives. The fund consists of cash invested in an interest-bearing account and is funded by quarterly cash payments. We contributed $641,000 in cash and interest to the fund during 2008 and withdrew $602,000, which was spent on reclamation activities. At December 31, 2008, the fund had a balance of $1.8 million. For 2009, quarterly contributions will remain at $150,000 to ensure that future obligations can be met.

Reclamation Fund Summary

($000s)	Cumulative Since Inception	2008	2007	2006
Reclamation fund, beginning balance	-	1,788	2,117	1,964
Reclamation fund contributions	4,093	641	470	455
Expenditures on reclamation	(2,266)	(602)	(799)	(302)
Reclamation fund, ending balance	1,827	1,827	1,788	2,117

Quarterly Performance and Trends

Our results are directly influenced by commodity prices, which are determined by supply and demand factors, weather, seasonality, global political events, general economic conditions, and changes in Canadian/U.S. dollar exchange rates. Quarterly variances in revenues, net income, cash provided by operating activities, and funds generated from operations are caused mainly by fluctuations in commodity prices, production volumes, and operating costs. Crude oil prices are generally determined by global supply and demand factors, but the variances do not have seasonable predictability. Natural gas prices are typically higher in winter months as heating demand rises, but this seasonality is significantly influenced by weather conditions and North American natural gas inventories.

The following significant changes have occurred over the last eight quarters that have influenced our results.

- WTI crude prices have exhibited significant volatility in the last eight quarters. Prices climbed steadily between January 2007 and July 2008, when they reached an all time high of over US$147 per barrel. During this period, rising oil prices boosted our revenues and cash distributions, although the gains were somewhat offset by the increase in the value of the Canadian dollar relative to its U.S. counterpart. WTI prices declined modestly through the third quarter and then plunged rapidly through the fourth quarter, causing revenues to decline sharply as well. The steep price decline was attributable to a drop in demand due to the rapidly deteriorating global economic picture.
- AECO natural gas prices have also exhibited significant volatility, averaging as low as Cdn$5.02 per Mcf in September 2007. Natural gas markets began to strengthen in the first quarter of 2008, and we benefited from higher natural gas prices in the first nine months of 2008. However, natural gas prices faced downward pressure through the fourth quarter of 2008.
- We have adjusted our monthly distributions in response to changing commodity prices. In January 2007, our distribution rate was $0.15 per Trust Unit. We raised the monthly rate to $0.18 per Trust Unit in April 2008, and raised it again in June, to $0.25 per Trust Unit. We also declared an additional distribution of $0.35 per Trust Unit for 2008. In January 2009, we lowered the monthly rate to $0.10 per Trust Unit to preserve operating stability and financial flexibility.
- The substantive enactment in June 2007 of Bill C-52 *Budget Implementation Act*, 2007, resulted in the initial recording of a $54.3 million future income tax expense in the second quarter of 2007. We are now required to record future income tax related to temporary differences at the Trust level, which represents the difference between the accounting and tax basis of the Trust's net assets. In addition, corporate tax rate reductions enacted in the fourth quarter of 2007 resulted in a future income tax recovery of $5.9 million.
- On July 7, 2008, we acquired certain royalty and minor working interests in Alberta for $8.5 million. On August 31, 2007, we acquired gross overriding royalty (GORR) interests on 309,800 gross acres of land in Alberta and Saskatchewan for $57.6 million. On September 5, 2007, we acquired a 7% GORR interest on 9,078 gross acres of land at Dixonville, Alberta, for $32.8 million. These acquisitions were funded through our credit facilities, which were increased to $210 million in the third quarter of 2007.
- Rising costs have been experienced industry wide and particularly in Alberta where strong economic growth and oil sands development have created increased demand for people and services. We have experienced higher operating expenses on our working interest properties, which currently comprise about 29% of our total production volumes. However, the effect of higher costs on our overall results is mitigated by our large proportion of royalty interest production, which is unencumbered by operating expenses.
- Fluctuations in our Trust Unit price during 2008 have resulted in corresponding changes in unit based incentive compensation, which are based in part on the closing unit price at each quarter end.
- Quarterly fluctuations in the percentage of our total boe production that is derived from royalty interests will result in corresponding fluctuations in operating expenses and third party royalty expenses. Over the past eight quarters, royalty production volumes have varied between 63% and 72% of total boe production.
- In the second quarter of 2007, two natural gas wells in British Columbia were converted from royalty interests to working interests upon payout. To account for the change in status of the two wells, royalty volumes and revenues were adjusted, and in their place working interest volumes and revenues were booked, along with associated operating and royalty expenses.

The accompanying table illustrates the fluctuations experienced over the past eight quarters and the resulting effect on our financial results. Discussion and analysis of fourth quarter events or items affecting our financial condition, cash flows, and results of operations is contained in our 2008 fourth quarter MD&A, which is incorporated by reference herein. Additional information about our quarterly results is provided in our interim reports, copies of which are available on SEDAR or on our website.

Quarterly Review

	2008				2007			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial ($000s, except as noted)								
Revenue, net of royalty expense	33,174	58,210	59,563	46,553	39,218	36,086	35,907	34,988
Distributions declared	54,387	37,050	30,114	22,198	28,096	22,165	22,151	22,133
Per Trust Unit ($) [1]	1.10	0.75	0.61	0.45	0.57	0.45	0.45	0.45
Net income (loss)	13,374	36,772	36,163	23,647	19,067	12,487	(42,533)	9,787
Per Trust Unit, basic and diluted ($)	0.27	0.74	0.73	0.48	0.39	0.25	(0.86)	0.20
Cash provided by operating activities	41,672	57,380	46,379	33,821	32,503	29,796	30,829	26,513
Per Trust Unit ($)	0.84	1.16	0.94	0.69	0.66	0.61	0.63	0.54
Funds generated from operations [2]	26,942	51,977	53,183	39,182	32,591	29,907	30,213	28,297
Per Trust Unit ($)	0.55	1.05	1.08	0.79	0.66	0.61	0.61	0.58
Property and royalty acquisitions	(782)	8,475	-	-	26	90,430	-	-
Capital expenditures	3,770	9,222	2,135	2,202	3,901	1,960	2,830	3,476
Long-term debt	140,000	141,000	151,000	169,000	178,000	179,000	100,000	99,000
Trust Units outstanding (basic)								
Weighted average (000s)	49,424	49,389	49,353	49,317	49,282	49,246	49,210	49,175
At quarter end (000s)	49,459	49,424	49,388	49,352	49,317	49,281	49,246	49,210
Operating ($/boe, except as noted)								
Daily production (boe/d)	7,779	7,613	7,674	8,152	8,591	8,219	8,566	8,564
Royalty interest production (%)	71	71	72	71	70	69	63	72
Average selling price	46.55	83.47	86.43	64.16	50.57	48.28	48.21	47.40
Operating netback [2]	42.14	79.14	81.21	59.18	46.47	43.65	42.28	42.06
Operating expenses	4.21	3.97	4.08	3.58	3.14	4.07	3.79	3.33
Working interest properties	14.31	13.51	14.37	12.54	10.56	13.17	10.34	11.82
General and administrative expenses	2.20	1.95	2.15	3.16	1.80	1.28	1.59	2.89
Benchmark Prices								
WTI crude oil (US$/bbl)	58.69	117.98	123.98	97.86	90.68	75.38	65.04	58.16
Exchange rate (Cdn$/US$)	0.83	0.96	0.99	1.00	1.02	0.96	0.91	0.85
Edmonton Par crude oil (Cdn$)	63.21	121.85	126.07	97.50	86.42	79.95	71.93	67.09
Light/heavy oil differential (Cdn$/bbl)	13.72	16.43	21.43	19.47	29.37	23.95	21.02	16.98
Bow River/Hardisty (Cdn$/bbl)	49.49	105.42	104.64	78.04	57.05	56.00	50.91	50.11
AECO natural gas (Cdn$/Mcf)	6.78	9.24	9.35	7.13	6.00	5.61	7.37	7.45
Unit Trading Performance								
High ($)	18.43	24.35	24.40	19.29	15.85	15.85	15.85	15.30
Low ($)	9.15	16.01	17.51	14.55	14.46	12.51	13.77	13.00
Close ($)	10.49	17.10	23.99	18.04	15.60	15.26	14.53	14.35
Volume (000s)	10,474	10,263	8,993	6,740	7,036	5,172	6,853	6,040

1 Based on the number of Trust Units issued and outstanding at each record date.
2 See Non-GAAP Measures.

Outlook

While supply and demand fundamentals point to higher prices over the long term, the short-term outlook remains clouded. The continuing deterioration in the economic outlook has reduced current and expected petroleum consumption. The resulting decline in commodity prices has dampened activity levels in western Canada, as lower prices have reduced producers' cash flows and therefore capital expenditure budgets. Industry drilling will be down sharply in 2009 and we expect that will be mirrored on our lands. Commodity prices may face further downward pressure in 2009, especially if demand continues to fall. However, reduced production by Canadian and world producers could allow for some price recovery later in the year.

Because of the weakened global economy, the lending capacity of financial institutions has been diminished and risk premiums have increased. In this environment, many businesses will have restricted access to capital and increased borrowing costs. These issues may affect our ability to access financing for potential future acquisitions.

On our working interest properties, we will continue to fund development activities from cash provided by operating activities. We anticipate spending approximately $12 million in 2009. Beyond that, we may need to access additional capital or curtail capital expenditure plans and if so, we will seek the most cost effective and efficient means of financing our ongoing operations.

We believe some producers may look to sell non-core oil and gas assets during 2009, to fund their core exploration and development programs or reduce debt. This should present opportunities for us to acquire additional royalty interests. Excluding any potential acquisitions, however, we are forecasting average production of 7,500 boe per day for 2009. This is about 5% lower than 2008 as royalty drilling and development activities on our working interest properties will be insufficient to fully offset natural production declines.

Distribution Policy

Our distribution policy takes into consideration forecasted cash provided by operating activities, debt levels, debt covenants, capital expenditures, and reclamation fund requirements. We have a declining asset base, and ongoing development activities and acquisitions are necessary to replace production and add additional reserves. The success of these activities, along with commodity prices, are the main factors influencing the sustainability of our distributions.

In the near term, with the expectation that commodity prices will remain weak, we have lowered our monthly distribution rate to preserve operating stability and financial flexibility in this low price environment. Our Board has established a distribution policy for the first half of 2009 of $0.10 per Trust Unit per month based on the key operating assumptions outlined below. We will review this policy monthly and make adjustments, if necessary, to ensure that cash distributions are in line with expected cash flow.

The following table outlines our key operating assumptions for 2009.

2009 Key Operating Assumptions

As at March 11, 2009

Average daily production	boe/d	7,500
Average WTI oil price	US$/bbl	44.00
Average AECO natural gas price	Cdn$/Mcf	5.00
Average exchange rate	Cdn$/US$	0.80
Average operating costs	$/boe	4.10
Average G&A costs	$/boe	2.90
Capital expenditures	$ millions	12
Long-term debt at year end	$ millions	159
Weighted average Trust Units outstanding	thousands	49,514
Estimated portion of distributions taxable as income	%	90-100%

Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including light/heavy oil price differentials), foreign exchange rates, or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators. Freehold is particularly vulnerable to swings in the light/heavy oil price differential, as approximately 33% of our total boe production is heavy oil.

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

Sensitivity Analysis

		Estimated Change in Distributions to Unitholders	
Variable	Change (+/-)	($000s)	($/Trust Unit)
WTI oil price	US$1.00/bbl	2,044	0.04
Light/heavy oil differential	Cdn$1.00/bbl	1,635	0.03
AECO natural gas price	Cdn$0.25/Mcf	1,292	0.03
Exchange rate	0.01	1,025	0.02
Interest rates	1%	1,353	0.03
Oil and NGL production	100 bbls/d	1,520	0.03
Natural gas production	1,000 Mcf/d	1,003	0.03

Alberta's New Royalty Framework

The Government of Alberta's New Royalty Framework (NRF) for Crown oil and gas royalty policy took effect January 1, 2009. The NRF has a sliding scale formula based on both commodity prices and well productivity. The royalty rate changes will see the oil and gas industry paying higher Alberta Crown royalties beginning in 2009, which may have a negative impact on producers' future cash flows.

However, we expect to see little impact on Freehold's current producing wells, given the mature nature of most of our producing assets. As well, the new royalty rates will only apply to our working interest production on Alberta Crown lands. Our royalty interest production in Alberta is not affected. Based on our 2008 reserve data, for 2009, using a WTI forecast price of US$53.73 per barrel, the implementation of the NRF results in a reduction in Crown Royalties payable for the year of approximately $200,000 as compared to the previous royalty regime. By 2014, when WTI is forecast to be US$93.85 per barrel, the NRF increases Crown royalties payable by approximately $360,000. By 2018, when WTI is forecast to be US$101.58 per barrel, the increase in royalties payable would be approximately $475,000. Overall, for total proved plus probable reserves, the NFR results in a reduction of $3.3 million to the net present value discounted at 10% and an estimated reduction in net reserves of 141,000 boe.

In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta introduced a five-year program of transitional royalty rates with the intent of promoting new drilling. Under this new program, companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be given a one-time option, on a well by well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. To qualify for this program, wells must be drilled during between January 1, 2009 and December 31, 2013. Following this period, all new wells drilled will be subject to the NRF.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta, including a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program, a $200 per metre royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by 2008 production levels and drilling activity between April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 MMcf of natural gas. Based on our 2008 production, we will be entitled to a maximum credit of 50% of royalties payable in the period April 1, 2009 and March 31, 2010 on qualifying wells.

SIFT Tax Strategy Update

Freehold, with its large, diversified asset base of primarily royalty interests, low risk profile, low sustaining capital requirements, and high payout ratio, is ideally suited to be an income trust. As such, we plan to retain the flow-through advantages of our current structure for as long as is prudent. However, with 2011 approaching, we must assess our options and examine our future strategic direction.

Our Board has formed a special committee of independent directors with a mandate to determine a course of action that best maximizes Unitholder value. This will be an involved process requiring careful due diligence. Among the most important considerations will be commodity price forecasts, the structures that our peers adopt, overall market sentiment, and future access to capital.

On July 14, 2008, the Department of Finance released draft amendments to the *Income Tax Act* (Canada) to facilitate the conversion of SIFT entities into corporations. We are currently assessing the draft rules as they relate to our particular circumstances. However, our current limited ability to generate tax pools makes conversion to a corporation a less obvious choice for Freehold than it is for many other oil and gas trusts. We anticipate the special committee's recommendation by the end of 2009.

Business Risks and Mitigating Strategies

The operations of an energy trust are subject to the same industry risks and conditions faced by conventional oil and gas companies. The most significant of these include:

- Fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and natural gas;
- Variations in currency exchange rates;
- Imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. Our reserves will deplete over time through continued production and we and our lessees 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 the current global financial crisis;
- Risk associated with the re-negotiation 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.

As a royalty trust, we are also subject to the following risks:

- Fifteen royalty payors account for about two-thirds of our royalty income, and changes to their businesses may have a significant effect on our results.
- Higher prime borrowing rates may increase interest expense on our debt and may make fixed income investments more attractive to investors of Trust Units.

For a further 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 ensure that we are paid royalties on our production from our lands in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken. During 2008, our audit staff issued audit exception queries amounting to $3.6 million, bringing the total amount of audit exception queries since 1997 to $32.1 million, of which we have successfully recovered $23.8 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 and do not anticipate a change in this policy.
- We employ a qualified team of oil and gas professionals with many years of experience and knowledge in managing our assets.
- We maintain levels of liability insurance that meet or exceed industry standards.
- We employ a conservative approach to debt management. As circumstances warrant, we allocate a portion of funds generated from operations to debt repayment.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of 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.

In 2002, the Government of Canada ratified the Kyoto Protocol, which calls for Canada to reduce its greenhouse gas emissions to specified levels. There has been much public debate about Canada's ability to meet these targets and the Government's strategy or alternative strategies on climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases, whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Trust.

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

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan encompasses three areas:

- carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation;
- energy conservation and efficiency; and
- greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage.

In addition to this action plan, the Provincial Energy Strategy, unveiled on December 11, 2008, is expected to support the upgrading, refining and petrochemical clusters existing in the province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

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

Health, Safety and Environment

Freehold is a member of the Canadian Association of Petroleum Producers (CAPP). We encourage our operators to participate and excel in the CAPP Stewardship Program by aligning their operations with industry best practices and communicating clearly that meeting or exceeding regulatory requirements is expected.

We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of the working interest properties upon abandonment. We have no reclamation responsibilities on our royalty assets, as these are the responsibility of the working interest owners. In 1996, we established a reclamation fund to ensure that required funds are available for future reclamation of working interest wells and facilities once they have reached the end of their economic life (see Reclamation Fund).

The Manager of Freehold has a comprehensive environment, health and safety program to protect the health and safety of its employees, contractors, and the public.

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 provide a reasonable level of assurance that they are effective, we do not expect that the disclosure controls and procedures or internal control over financial reporting 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 the Trust's disclosure controls and procedures as of March 11, 2009. 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 relating to the Trust is made known to management on a timely basis.

Internal Control Over Financial Reporting

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

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

On August 15, 2008, the Canadian Securities Administrators published its final version of NI 52-109, effective for our 2008 year-end reporting. NI 52-109 includes the certification of the operating effectiveness of internal control over financial reporting (ICFR). It requires the use of a control framework to design and evaluate internal controls, provides specific guidance regarding the documentation, testing and evaluation of controls, and clarifies the definition of material weaknesses and conclusions on disclosure controls and procedures when there is a material weakness in ICFR.

The CEO and CFO of the Trust are responsible for establishing and maintaining internal control over financial reporting (ICFR), as such term is defined in NI 52-109. 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, the Trust conducted an evaluation of the effectiveness of its ICFR as at December 31, 2008, as structured within the COSO Framework. Based on this evaluation, the CEO and CFO concluded that, as of December 31, 2008, the Trust's 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 the Trust's ICFR during 2008 that materially affected the Trust's ICFR.

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

On January 1, 2008, we adopted the CICA Handbook Section 1535 Capital Disclosures, Section 3862 Financial Instruments – Disclosures, and Section 3863 Financial Instruments – Presentation.

Section 1535 Capital Disclosures establishes standards for disclosing information about capital and how it is managed. This section specifies the disclosure about:

(i) our objectives, policies, and processes for managing capital;
(ii) quantitative data about what we regard as capital; and
(iii) whether we have complied with any capital requirements and the consequences in the event of non-compliance.

Section 3862 Financial Instruments – Disclosures and Section 3863 Financial Instruments – Presentation replace Handbook Section 3861 Financial Instruments – Disclosure and Presentation and require increased emphasis on the risks associated with both recognized and unrecognized financial instruments and disclosure of how those risks are managed. The new presentation standard carries forward the former presentation requirements.

The implementation of these new standards had no impact on our financial results; however they did result in additional disclosure in the notes to the interim consolidated financial statements for the three and twelve months ended December 31, 2008.

International Financial Accounting Standards (IFRS)

In January 2006, the Canadian Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under International Financial Reporting Standards (IFRS), which will replace Canadian GAAP. In February 2008, the AcSB confirmed January 1, 2011 as the changeover date to commence reporting under IFRS. Currently, we are assessing the standards to determine the impact on our consolidated financial statements. We are also in the process of finalizing our plan, which will address resources required, employee training, continued analysis of key accounting standard differences, evaluation of information system requirements, and an impact assessment on operations, internal controls over financial reporting and disclosures. Throughout the year, we will provide IFRS conversion progress updates as this information becomes available.

Accounting Policies and Critical Estimates

Our financial statements are prepared within a framework of GAAP selected by management and approved by our Board. The assets, liabilities, revenues, and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. The more significant reporting areas are crude oil and natural gas reserve estimation, depletion, impairment of assets, oil and gas revenue accruals, asset retirement obligations, and future income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists, and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

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

Reserve Estimates, Depletion and Ceiling Test

The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2008. Reserve estimates are updated once a year (as at December 31) and when a significant acquisition is completed. The reserve and recovery information provided are only estimates. The actual production and ultimate reserves may be greater than or less than the estimates and the differences may be material.

We follow the full cost method of accounting for petroleum and natural gas interests. Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in the depletion rate. As at December 31, 2008, the depletion calculation included $1.2 million for estimated future development costs associated with proved undeveloped reserves and excluded $33.9 million for the lower of cost and estimated value of unproved lands.

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties. The ceiling test estimates were reviewed at year-end to ensure that they are reasonable and supportable in light of current economic conditions. The ceiling test, performed as at December 31, 2008, indicated that the undiscounted future net revenues from proved reserves exceed the net book value of the properties. Accordingly, no write down of oil and gas properties was required.

Accruals

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

Asset Retirement Obligation

Accounting standards require us to recognize the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on the unit-of-production method over the life of the reserves. Once the initial asset retirement obligation is measured, it must be adjusted at the end of each period to reflect the passage of time as well as changes in the estimated future cash flows that underlie the obligation.

We have no asset retirement obligations on our royalty income properties. Our asset retirement obligation results from the responsibility to abandon and reclaim our net share of all working interest properties. The net present value of our total asset retirement obligation is estimated to be $5.7 million (discounted at a weighted average credit adjusted risk free rate of 5.7%), with the undiscounted value being $17.3 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away.

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

Future Income Taxes

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

Unit Based Compensation

Effective January 1, 2006, we began funding a portion of the Manager's LTIP. The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units 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. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. As participants in the Manager's LTIP receive a cash payment on a fixed vesting date, compensation expense is determined based on the intrinsic value of the rights at each period end. The valuation incorporates the period end Trust Unit price, the number of rights outstanding at each period end, and certain management assumptions. Compensation expense is recognized over the vesting period with a corresponding increase or decrease in liabilities. We have not incorporated an estimated forfeiture rate for rights that will not vest; rather, we account for actual forfeitures as they occur (see Unit Based Compensation).

A deferred trust unit plan was established in 2006 for the non-management directors of Freehold whereby fully vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. Compensation expense is recognized at market value at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital (see Trust Units Outstanding and Unit Based Compensation).

Management's Report

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

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

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

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

David J. Sandmeyer
President and Chief Executive Officer

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

March 11, 2009

Auditors' Report

To the Unitholders of Freehold Royalty Trust:

We have audited the consolidated balance sheets of Freehold Royalty Trust as at December 31, 2008 and 2007 and the consolidated statements of income (loss), comprehensive income (loss) and deficit and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. 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 plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2008 and 2007, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KPMG LLP
Chartered Accountants
Calgary, Canada

March 11, 2009

Consolidated Balance Sheets

($000s)		December 31, 2008		December 31, 2007
Assets				
Current assets:				
Cash	$	537	$	393
Accounts receivable		23,261		26,802
		23,798		27,195
Reclamation fund (note 5)		1,827		1,788
Deferred long-term compensation (note 7)		120		697
Petroleum and natural gas interests (note 3)		426,530		474,520
	$	452,275	$	504,200
Liabilities and Unitholders' Equity				
Current liabilities:				
Distributions payable to Unitholders	$	29,676	$	7,398
Accounts payable and accrued liabilities		14,094		8,578
Current portion of unit based compensation payable (note 7)		83		-
		43,853		15,976
Asset retirement obligation (note 5)		5,663		6,608
Unit based compensation payable (note 7)		243		1,106
Long-term debt (note 4)		140,000		178,000
Future income tax liability (note 9)		42,511		51,404
Unitholders' equity:				
Unitholders' capital (note 6)		567,310		564,828
Contributed surplus (note 7)		722		512
Deficit		(348,027)		(314,234)
		220,005		251,106
	$	452,275	$	504,200

See accompanying notes to consolidated financial statements.

Approved on behalf of Freehold Royalty Trust by Freehold Resources Ltd., as Administrator:

William W. Siebens
Director

D. Nolan Blades
Director

Consolidated Statements of Income (Loss), Comprehensive Income (Loss) and Deficit

($000s, except per unit and weighted average data)	2008	Year ended December 31, 2007
Revenue:		
Royalty income and working interest sales	$ 204,116	$ 152,184
Royalty expense and mineral tax	(6,616)	(6,263)
	197,500	145,921
Expenses:		
Operating	11,299	11,076
General and administrative	6,790	5,854
Unit based compensation (note 7)	97	631
Interest on long-term debt	7,039	7,005
Depletion and depreciation	67,948	72,400
Accretion of asset retirement obligation (note 5)	384	266
Management fee (note 8)	2,482	2,130
	96,039	99,362
Net income before taxes	101,461	46,559
Income and capital taxes (note 9)	398	179
Future income tax expense (reduction) (note 9)	(8,893)	47,572
	(8,495)	47,751
Net income (loss) and comprehensive income (loss)	109,956	(1,192)
Deficit, beginning of year	(314,234)	(218,497)
Distributions declared	(143,749)	(94,545)
Deficit, end of year	$ (348,027)	$ (314,234)
Net income (loss) per Trust Unit, basic and diluted	$ 2.23	$ (0.02)
Weighted average number of Trust Units:		
Basic	49,370,878	49,228,411
Diluted	49,412,670	49,228,411

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

($000s)	2008	Year ended December 31, 2007
Cash provided by (used in):		
Operating:		
Net income (loss)	$ 109,956	$ (1,192)
Items not involving cash:		
Depletion and depreciation	67,948	72,400
Unit based compensation	7	631
Future income tax expense (reduction)	(8,893)	47,572
Accretion of asset retirement obligation	384	266
Trust Units issued in lieu of management fee	2,482	2,130
Expenditures on reclamation	(602)	(799)
	171,282	121,008
Changes in non-cash working capital (note 10)	7,970	(1,367)
	179,252	119,641
Financing:		
Long-term debt	(38,000)	78,000
Distributions paid	(121,471)	(94,524)
	(159,471)	(16,524)
Investing:		
Property and royalty acquisitions	(7,693)	(90,456)
Capital expenditures	(12,992)	(12,167)
Change in reclamation fund	(39)	329
Changes in non-cash working capital (note 10)	1,087	(851)
	(19,637)	(103,145)
Increase (decrease) in cash	144	(28)
Cash, beginning of year	393	421
Cash, end of year	$ 537	$ 393

See accompanying notes to consolidated financial statements.

Notes to the Consolidated Financial Statements

Years ended December 31, 2008 and 2007

Basis of Presentation

Freehold Royalty Trust (the Trust) is an open-ended investment trust formed under the laws of the Province of Alberta pursuant to a Trust Indenture dated September 30, 1996 as amended from time to time. The Trust holds royalty interests directly and a 99% royalty interest in the funds generated by its wholly owned subsidiary, Freehold Resources Ltd. (Freehold Resources). Freehold Resources was incorporated on June 3, 1996 and derives its income from certain petroleum and natural gas working interest properties. The Trust also holds royalty interests and working interests through Petrovera Resources (Petrovera), a general partnership acquired on May 10, 2005.

These consolidated financial statements include the accounts of the Trust, Freehold Resources and Petrovera. All inter-entity transactions have been eliminated.

1. Significant Accounting Policies

(a) Petroleum and Natural Gas Interests

The Trust follows the full cost method of accounting.

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

(b) Ceiling Test

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties.

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

(c) Depletion

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

(d) Asset Retirement Obligation

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

(e) Income and Other Taxes

The Trust is a taxable trust under the *Income Tax Act* (Canada) and it distributes substantially all of its taxable income to its Unitholders. The tax deductions received by the Trust for the distributions to Unitholders represent an exemption from taxation equivalent to the Trust's earnings.

The Trust follows the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Freehold Resources can deduct royalty payments to the Trust in determining taxable income and is generally liable for income taxes on its 1% residual interest.

(f) Use of Estimates

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

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

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

(g) Unit Based Compensation Plans

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

In addition, a deferred trust unit plan has been established for the non-management directors of Freehold whereby fully-vested deferred trust units are granted annually. Under this plan, distributions to Unitholders declared prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of distribution. Compensation expense is recognized at the market value of the Trust Units at the time of grant or distribution with a corresponding increase to contributed surplus. Upon redemption of the deferred trust units for Trust Units, the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' capital.

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

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

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

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

The Trust did not identify any material embedded derivatives which required separate recognition and measurement.

2. New Accounting Standards
On January 1, 2008, the Trust adopted the new Canadian accounting standards relating to financial instruments and capital disclosures.

(a) Capital Management
Freehold Royalty Trust is structured as a mutual fund trust under the *Income Tax Act* (Canada). This enables us to return the majority of our income to Unitholders in a tax-effective manner. We receive revenue from oil and gas properties as reserves are produced, which is paid to Unitholders on a regular basis over the economic life of the properties. The Trust's objective for managing capital is to maximize long-term Unitholder value by distributing to Unitholders any cash that is not required for financing our operations or capital investment growth opportunities that may offer Unitholders better value.

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

We retain working capital primarily to fund capital expenditures or acquisitions and reduce bank indebtedness. The Trust's distribution policy includes withholding a portion of cash provided by operating activities for contributions to the Trust's reclamation fund to provide a cash reserve for the eventual abandonment of oil and gas properties.

Our Trust Indenture provides that not more than 49% of the Trust's Units can be held by non-residents of Canada. We monitor foreign ownership levels on a regular basis through declarations from Unitholders and geographical searches. Accordingly, the reported level of Canadian ownership is subject to these limitations, and the level of Canadian ownership can change at any time without notice.

As a result of the Canadian trust taxation legislation passed in June 2007 and effective January 1, 2011, the Trust is subject to certain capital growth restrictions referred to as "normal growth" equity guidelines. These guidelines limit the amount of Unitholders' capital that can be issued by the Trust in each of the next three years, based on the Trust's market capitalization on October 31, 2006. Our market capitalization as of the close of trading on October 31, 2006 was approximately $929 million, which means our safe harbour equity growth amount for calendar 2008 was $557 million, and for each of calendar 2009 and 2010 is an additional $186 million with an ultimate total equity growth amount of no more than $929 million.

We are bound by covenants on our credit facilities. The covenants are monitored monthly as part of management's internal review to ensure compliance with the requirements. Under our credit facility, we are restricted from making distributions 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, 2008, the Trust was in compliance with all such covenants.

Capitalization

($000s, except as noted)	2008	2007
Unitholders' equity	$ 220,005	$ 251,106
Long term debt	140,000	178,000
Working capital	20,055	(11,219)
Net debt	160,055	166,781
Cash provided by operating activities for last 12 months	179,252	119,641
Change in non-cash working capital	(7,970)	1,367
Trailing 12 months funds generated from operations	171,282	121,008
Net debt to trailing 12 month funds generated from operations (times)	0.9	1.4

(b) Financial Instrument Risk Management

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

(i) Credit risk

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

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

The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure. We did not have an allowance for doubtful accounts as at December 31, 2008 and December 31, 2007 and did not provide for any doubtful accounts nor were we required to write off any receivables during the year ended December 31, 2008 or the years ended December 31, 2007 and 2006.

The Trust markets approximately 58% of its production along with the operator or royalty payor under the terms of a diverse number of agreements. When it can, the Trust takes its production in kind (currently 42%) and sells to two primary purchasers with a proven history in the industry.

(ii) Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We maintain a conservative approach to debt management that aims to provide maximum financial flexibility with respect to acquisitions and development expenditures, while maintaining stable distributions. At December 31, 2008, there was $70 million of available capacity under our credit facilities. As circumstances warrant, we allocate a portion of cash provided by operating activities to debt repayment. We prepare annual capital expenditure budgets, which are regularly monitored and updated.

(iii) Market risk

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

Foreign currency exchange rate risk

We do not sell or transact in any foreign currency; however, the underlying market prices in Canada for oil and natural gas are influenced by changes in the exchange rate between the Canadian and U.S. dollar. During the year ended December 31, 2008, we had no foreign exchange related derivative contracts in place. Assuming all other variables held constant, a $0.01 change (plus or minus) in the U.S./Canadian dollar exchange rate for the year ended December 31, 2008, would have resulted in a corresponding change to net income of approximately $2.1 million (2007 – $1.6 million).

Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate with changes in commodity prices. Commodity prices for oil and natural gas are influenced by the relationship between the Canadian and U.S. dollar as well as macroeconomic events that dictate the levels of supply and demand. During the year ended December 31, 2008, we had no commodity price related derivative contracts in place. Assuming all other variables held constant, a US$1.00 change (plus or minus) in the WTI crude oil price for the year ended December 31, 2008, would have resulted in a corresponding change to net income of approximately $1.4 million (2007 – $1.4 million). A $0.25 change (plus or minus) in the AECO natural gas price would have resulted in a corresponding change to net income of approximately $1.5 million (2007 – $1.6 million).

Interest rate risk

We are exposed to interest rate risk on outstanding bank debt, which has a floating interest rate, and fluctuations in interest rates would impact our future cash flows. Assuming all other variables held constant, a 1% change (plus or minus) in the interest rate for the year ended December 31, 2008 would have resulted in a corresponding change to net income of approximately $1.6 million (2007 – $1.3 million).

(c) International Financial Reporting Standards

In January 2006, the Canadian Accounting Standards Board (AcSB) adopted a strategic plan for the direction of accounting standards in Canada. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under International Financial Reporting Standards (IFRS), which will replace Canadian GAAP. In February 2008, the AcSB confirmed January 1, 2011 as the changeover date to commence reporting under IFRS. Currently, we are assessing the standards to determine the impact on our consolidated financial statements. We are also in the process of finalizing our plan, which will address resources required, employee training, continued analysis of key accounting standard differences, evaluation of information system requirements, and an impact assessment on operations, internal controls over financial reporting and disclosures. Throughout the year, we will provide IFRS conversion progress updates as this information becomes available.

3. Petroleum and Natural Gas Interests

($000s)		2008		2007
Petroleum and natural gas interests	$	876,609	$	856,651
Accumulated depletion and depreciation		(450,079)		(382,131)
Petroleum and natural gas interests, net	$	426,530	$	474,520

The depletion calculation included $1.2 million (2007 – $0.6 million) for estimated future development costs associated with proved undeveloped reserves and excluded $33.9 million (2007 – $30.3 million) for the lower of cost and market value of unproved lands.

The Trust's ceiling test calculation, performed at December 31, 2008, resulted in no impairment loss. The future prices used by the Trust in estimating cash flows were based on forecasts by an independent qualified reserves evaluator, adjusted for the Trust's quality, transportation, and contract differences. The following table summarizes the benchmark prices used in the calculation.

Year	WTI Crude Oil (US$/bbl)	Foreign Exchange Rate	Edmonton Par Crude Oil (Cdn$/bbl)	AECO Natural Gas (Cdn$/MMBtu)
2009	53.73	0.80	65.35	6.82
2010	63.41	0.85	72.78	7.56
2011	69.53	0.85	79.95	7.84
2012	79.59	0.90	86.57	8.38
2013	92.01	0.95	94.97	9.20
Average annual increase, thereafter	2%	-	2%	2%

4. Long-term Debt

Freehold has a $195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which $140 million was drawn at December 31, 2008. The facility is extendible annually. In the event that the lenders' do not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period, which is May 2009. In addition, Freehold has available a $15 million extendible revolving operating facility.

Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 100 to 170 basis points and standby fees. The facilities are secured with $300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants.

Freehold's borrowing base is dependent on our lenders annual review and interpretation of our reserves and future commodity prices, with the next renewal to occur by May 2009.

5. Asset Retirement Obligation

The Trust has no asset retirement obligations on its royalty interest properties. The Trust's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of the Trust's total asset retirement obligations are estimated to be $5.7 million (discounted at a weighted average credit adjusted risk free rate of 5.7%), with the undiscounted value being $17.3 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away.

($000s)		2008		2007
Balance, beginning of year	$	6,608	$	4,598
Liabilities incurred		381		675
Liabilities settled		(602)		(799)
Revision in estimates [1]		(1,108)		1,868
Accretion expense		384		266
Balance, end of year	$	5,663	$	6,608

1 Revision in estimates is mainly a result of a decrease in the inflation rate, increase in estimates to well abandonment costs and changes to abandonment years.

A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. All liabilities settled during the periods are paid from the reclamation fund.

6. Unitholders' Capital

The Trust has authorized an unlimited number of Trust Units of which 49,459,429 were issued and outstanding at December 31, 2008 (2007 – 49,316,813).

Trust Units Issued and Outstanding

	2008		2007	
	Number	Amount ($000s)	Number	Amount ($000s)
Balance, beginning of year	49,316,813	$ 564,828	49,174,197	$ 562,698
Issued in lieu of management fee	142,616	2,482	142,616	2,130
Balance, end of year	49,459,429	567,310	49,316,813	564,828

In May 2006, the Trust reserved an additional 800,000 Trust Units pursuant to its management agreement with the Manager, of which 315,909 have been issued. In addition the Trust has reserved 200,000 Trust Units pursuant to the deferred trust unit plan.

The Trust is an open-ended mutual fund under which Unitholders have the right to request redemption directly from the Trust. Pursuant to the Amended and Restated Trust Indenture, Trust Units tendered by holders are subject to redemption under certain terms and conditions including the determination of the redemption price at the lower of the closing market price on the Toronto Stock Exchange on the date the Trust Units are tendered for redemption or 90% of the weighted average trading price for the 10-day trading period commencing on the tender date. Cash payments for Trust Units tendered for redemption are limited to $100,000 per month.

7. Unit Based Compensation

(a) Manager's LTIP

The Trust participates in its proportionate share of a long-term incentive compensation plan for all employees of the Manager (the Manager's LTIP). The Manager's LTIP will result in employees receiving cash compensation in relation to the value of a specified number of notional units. The Manager's LTIP uses a combination of the value of phantom Rife shares and Trust Units 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. Distributions made by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. Upon vesting, the employee is entitled to a cash payout based on the Trust Unit price. In addition, there is a performance multiplier based in part on the Trust's performance over the vesting period, which may range from 0.25 to 1.5 times the market value.

The total recovered for the year ended December 31, 2008 was $203,000 (2007 – expensed $366,000). At December 31, 2008, Freehold recorded $120,000 (2007 – $697,000) as a deferred long-term compensation asset representing the portion of the liability not yet charged to earnings. In addition, Freehold accrued $243,000 (2007 – $1,106,000) as a long-term liability and $83,000 (2007 – $nil) as a current liability.

(b) Deferred Trust Unit Plan

The deferred trust unit plan consists of fully vested deferred trust units which are granted annually. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units on the date of distribution. As at December 31, 2008 there were 44,087 deferred trust units outstanding which are redeemable for an equal number of Trust Units any time after the director's retirement.

Deferred Trust Units

	2008	2007
Balance, beginning of year	30,473	12,559
Annual grant	12,540	14,181
Units cancelled	(4,505)	-
Prior years adjustment	(311)	-
Additional units resulting from distributions	5,890	3,733
Balance, end of year	44,087	30,473

For the year ended December 31, 2008, the Trust expensed $300,000 (2007 – $265,000) as unit based compensation. The corresponding increase to contributed surplus for the year ended December 31, 2008 was $210,000 (2007 – $265,000), as $90,000 was a cash expense for the cancellation of deferred trust units.

Contributed Surplus

($000s)		2008		2007
Balance, beginning of year	$	512	$	247
Trust Unit incentive compensation expense		210		265
Balance, end of year	$	722	$	512

(c) Per Unit Amounts

For the purpose of calculating diluted net loss per Trust Unit for the year ended December 31, 2007, 28,507 incremental Trust Units from assumed redemption of deferred trust units are not included due to the anti-dilutive effect.

8. Related Party Transactions

The Manager provides certain services for a fee based on a specified number of Trust Units per quarter, pursuant to a management agreement which has a term of three years and will be renewed on November 26, 2010 unless terminated. During 2008, the management fee paid was 142,616 Trust Units with an ascribed value of $2.5 million (2007 – 142,616 Trust Units with an ascribed value of $2.1 million).

During the year, the Manager charged the Trust $5.3 million (2007 – $4.4 million) in general and administrative costs. At December 31, 2008, there was $nil (2007 – $0.3 million) included in accounts payable relating to these costs. The transactions were in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the Trust and the Manager.

9. Income Taxes

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

($000s, except as noted)		2008		2007
Earnings before income taxes and capital taxes	$	101,461	$	46,559
Combined federal and provincial tax rate		30.0%		32.7%
Computed expected income tax expense	$	30,421	$	15,234
Increase (decrease in income tax resulting from:				
Non-taxable earnings of the Trust		(40,803)		(14,024)
Impact of future rate reductions		1,273		(1,479)
Changes in enacted tax rates		-		(7,093)
SIFT legislated tax		-		54,798
Unit based compensation		90		134
Capital taxes		398		179
Other		126		2
Total income and capital taxes	$	(8,495)	$	47,751

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

($000s)		2008		2007
Future income tax liabilities:				
Petroleum and natural gas interests	$	44,023	$	53,539
Future income tax assets:				
Asset retirement obligations		(1,512)		(2,135)
Net future income tax liability	$	42,511	$	51,404

On a consolidated basis, the Trust's carrying value for book purposes exceeds the amount available for tax purposes by $208 million.

In 2007, income trust legislation was passed resulting in a two-tiered tax structure subjecting distributions to the federal corporate tax rate plus a deemed 13% provincial income tax at the Trust level starting in 2011. Currently, distributions paid to Unitholders are claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and paid by the Unitholder, depending on his or her own tax status. Due to this legislation, the future tax position of the Trust is reflected in the consolidated future income tax calculation.

On February 1, 2008, the federal government announced, as part of the federal budget, that the provincial component of the tax at the Trust level is to be calculated based on the general provincial rate in each province in which the Trust has a permanent establishment. This is the same method that a corporation would calculate its provincial tax rate. As these proposed rules were not substantively enacted as of December 31, 2008, the Trust has not reflected a reduced provincial component of the combined tax rate in calculating future income taxes for 2008.

The Trust's future tax liability relates primarily to the situation whereby its assets have a high book value relative to their associated tax value. This results in significant taxable temporary differences that reverse over time. Since the SIFT legislation will not take effect until 2011, a sizeable portion of the temporary differences will reverse during the period when the tax rate applicable to the assets continues to be nil. The combined federal and provincial tax rate used in the rate reconciliation is higher than the rate that will apply to the Trust because the SIFT tax will not apply until 2011 and is nil until that time.

10. Supplemental Cash Flow Disclosure

Changes in Non-Cash Working Capital Balance

($000s)		2008		2007
Accounts receivable	$	3,541	$	3,048
Accounts payable and accrued liabilities		5,516		(5,267)
	$	9,057	$	(2,219)

Cash Expenses Paid

($000s)		2008		2007
Interest	$	6,753	$	7,256
Taxes		329		(690)

Ten-Year Historical Review

	2008	2007	2006	2005	2004	2003	2002	2001	2000	1999
Financial ($000s, except as noted)										
Gross revenue	204,116	152,184	143,067	136,914	78,491	73,166	63,143	61,885	64,500	36,355
Funds generated										
from operations	171,282	121,008	119,849	118,034	64,313	60,658	51,489	49,728	51,882	27,304
Per Trust Unit ($)	3.47	2.46	2.44	2.76	2.04	1.95	1.71	1.72	1.94	1.03
Net income (loss) [1]	109,956	(1,192)	45,181	58,346	36,892	37,078	27,529	27,304	31,758	8,714
Per Trust Unit ($)	2.23	(0.02)	0.92	1.36	1.17	1.19	0.91	0.95	1.19	0.33
Distributions declared	143,749	94,545	103,100	84,810	54,490	53,149	39,530	45,264	35,226	20,757
Per Trust Unit ($)	2.91	1.92	2.10	1.92	1.73	1.70	1.31	1.56	1.32	0.78
Capital expenditures	12,992	12,167	11,446	7,982	5,823	5,894	2,946	2,992	5,161	940
Acquisitions	7,693	90,456	5,382	351,705	13,061	3,386	2,326	29,707	5,326	–
Long-term debt	140,000	178,000	100,000	107,000	27,000	18,000	30,000	33,000	38,000	39,288
Unitholders' equity	220,005	251,106	344,448	399,471	164,822	180,992	185,326	196,317	182,898	185,742
Operating										
Production										
Oil (bbls/d)	4,568	5,034	4,865	4,488	3,594	3,688	3,926	3,873	3,353	2,921
NGL (bbls/d)	337	333	358	345	283	317	288	354	327	302
Natural gas (MMcf/d)	17.4	18.7	19.1	16.8	10.3	10.9	10.7	11.2	11.0	11.2
Oil equivalent (boe/d)	7,804	8,484	8,412	7,636	5,588	5,817	6,004	6,086	5,523	5,082
Average sales price										
Oil ($/bbl)	83.45	54.38	50.24	46.65	38.08	32.77	31.25	24.42	32.98	21.82
NGL ($/bbl)	67.60	53.53	50.29	50.58	37.29	30.95	25.09	29.91	32.81	16.94
Natural gas ($/Mcf)	8.15	6.47	6.54	8.55	6.28	6.18	3.81	5.64	4.71	2.48
Oil equivalent ($/boe)	69.93	48.63	46.07	48.53	37.91	34.01	28.44	27.63	31.39	18.99
Operating netback ($/boe)	65.18	43.54	42.64	45.49	34.05	30.51	25.43	24.30	28.26	17.10
Land (gross acres) (000s)	2,375	2,380	2,069	2,006	1,067	1,011	1,001	1,005	872	869
Undeveloped land (gross acres) (000s)	651	589	598	555	292	242	235	237	141	136
Reserves (Mboe) [2]	25,374	27,963	28,012	30,530	21,163	22,052	26,813	28,177	28,150	29,062
Net asset value ($) [3]	13.92	11.85	11.65	13.85	8.92	8.08	8.74	7.51	8.65	6.23
Reserve life index (years)	9.8	9.5	9.6	9.9	10.6	11.0	12.2	12.7	14.0	15.7
Trust Units										
High ($)	24.40	15.85	23.06	19.30	18.42	17.19	11.35	10.10	9.50	6.90
Low ($)	9.15	12.51	12.43	14.25	14.02	10.50	9.00	8.00	5.60	4.13
Close ($)	10.49	15.60	14.81	18.81	17.45	16.35	10.88	9.20	8.70	5.95
Volume (000s)	36,469	25,101	35,512	28,320	11,567	10,970	7,323	8,162	6,752	5,782
Outstanding (millions)										
At period end	49.5	49.3	49.2	49.0	31.5	31.5	30.2	30.1	26.7	26.6
Weighted average	49.4	49.2	49.1	42.8	31.5	31.2	30.2	28.8	26.7	26.6

1 2003 and prior years were restated in 2004 for the adoption of new Canadian standards for asset retirement obligations.

2 Net proved plus probable reserves for 2003 through 2008. Reserves for prior years are gross established and are not directly comparable due to a change in reserves definitions and evaluation methodology in 2003.

3 2005 and prior years exclude asset retirement obligation.

Directors and Officers

Directors

William W. Siebens Calgary, Alberta
President and Chief Executive Officer,
Candor Investments Ltd.
Director since July 29, 1996

David J. Sandmeyer Calgary, Alberta
President and Chief Executive Officer,
Rife Resources Ltd.
Director since July 29, 1996

D. Nolan Blades Calgary, Alberta
President,
Sunny Gables Holdings Ltd.
Chair of the Audit, Corporate SIFT Tax Strategy and Reserves committees, Member of the Compensation Committee
Director since July 29, 1996

Harry S. Campbell Calgary, Alberta
Vice-Chair,
Burnet, Duckworth & Palmer LLP
Member of the Corporate SIFT Tax Strategy, Governance and Reserves committees
Director since July 29, 1996

Tullio Cedraschi Montreal, Quebec
Corporate Director
Member of the Corporate SIFT Tax Strategy and Governance committees
Director since January 21, 1998

Peter T. Harrison Montreal, Quebec
Senior Vice-President,
Montrusco Bolton Investments Inc.
Chair of the Compensation Committee, Member of the Audit, Corporate SIFT Tax Strategy and Reserves committees
Director since July 29, 1996

Russell J. Hiscock Montreal, Quebec
President and Chief Executive Officer,
CN Investment Division
Director since May 7, 2008

P. Michael Maher Calgary, Alberta
Professor,
Haskayne School of Business
Chair of the Governance Committee, Member of the Audit and Compensation committees
Director since July 29, 1996

Officers

William W. Siebens
Chairman

David J. Sandmeyer
President and Chief Executive Officer
Employee of Rife Resources Ltd. since 1982

William O. Ingram
Executive Vice-President and Chief Operating Officer
Employee of Rife Resources Ltd. since 1984

Darren G. Gunderson
Vice-President, Finance and Chief Financial Officer
Employee of Rife Resources Ltd. since 1991

Garry W. Bieber
Vice-President, Production
Employee of Rife Resources Ltd. since 1985

J. Frank George
Vice-President, Exploitation
Employee of Rife Resources Ltd. since 1983

Michael J. Okrusko
Vice-President, Land
Employee of Rife Resources Ltd. since 1982

Michael J. Mogan
Controller
Employee of Rife Resources Ltd. since 2003

Karen C. Taylor
Manager, Investor Relations and Corporate Secretary
Employee of Rife Resources Ltd. since 1997

Auditors
KPMG LLP

Bankers
CIBC
Royal Bank of Canada
Toronto-Dominion Bank

Independent Engineers
Trimble Engineering Associates Ltd.

Legal Counsel
Burnet, Duckworth & Palmer LLP

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Email: ktaylor@rife.com
Website: www.freeholdtrust.com

Management
Freehold is managed by Rife Resources Ltd. based in Calgary, Alberta.

Annual Meeting
The Annual Meeting of the Unitholders of Freehold will be held at 3:30 p.m. (MDT) on Wednesday, May 13, 2009 at the Sun Life Plaza Conference Centre, Calgary, Alberta. Unitholders are encouraged to attend and participate in the business of the meeting.

Designed by Bryan Mills Iradesso

Freehold

ROYALTY TRUST

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