

Freehold Royalty Trust Announces 2007 Fourth Quarter and Year End Results

FOURTH QUARTER HIGHLIGHTS

- Revenue was \$40.5 million, up 26% from the fourth quarter of 2006.
- Net income rose 100% to \$19.1 million (\$0.39 per Trust Unit) including a future income tax recovery of \$5.9 million.
- Funds generated from operations increased 19% to \$32.6 million (\$0.66 per Trust Unit).
- Distributions declared in the fourth quarter amounted to \$0.57 per Trust Unit, including a \$0.12 additional payment on December 15, 2007 due to increased income in 2007.
- Production averaged 8,591 barrels of oil equivalent (boe) per day, up 3% quarter over quarter.
- Price realizations averaged \$50.57 per boe, 22% higher than the fourth quarter a year ago.
- Operating netback was \$46.47 per boe, up 20% from last year.
- Land holdings increased 15% to 2.4 million gross acres, including 589,099 gross acres of undeveloped land independently valued at \$30.3 million.
- Net reserve additions of approximately 3.1 million boe replaced 100% of annual production at an average cost of \$32.15 per boe.
- Proved plus probable net reserves remained level year over year at approximately 28.0 million boe.
- At December 31, 2007, the present value of our net proved plus probable oil and gas reserves, discounted at 10% and before income taxes, was \$711.6 million, contributing to a net asset value of \$11.99 per Trust Unit.

The next regular monthly distribution of \$0.15 per Trust Unit will be paid on April 15, 2008, to Unitholders of record on March 31, 2008 (ex-distribution date March 27, 2008). Including the April 15, 2008 payment, 12-month trailing cash distributions total \$1.92 per Trust Unit.

Results at a Glance	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
Financial (\$000s, except as noted)						
Gross revenue	40,511	32,214	26%	152,184	143,067	6%
Net income (loss) (\$000s)	19,067	9,545	100%	(1,192)	45,181	-103%
Per Trust Unit, basic and diluted (\$)	0.39	0.19	105%	(0.02)	0.92	-102%
Funds generated from operations (\$000s)	32,591	27,394	19%	121,008	119,849	1%
Per Trust Unit (\$)	0.66	0.56	18%	2.46	2.44	1%
Capital expenditures	3,901	3,766	4%	12,167	11,446	6%
Property and royalty acquisitions (net)	26	—	—	90,456	5,382	1581%
Distributions declared	28,096	23,594	19%	94,545	103,100	-8%
Per Trust Unit (\$) ⁽¹⁾	0.57	0.48	19%	1.92	2.10	-9%
Long-term debt, period end	178,000	100,000	78%	178,000	100,000	78%
Unitholders' equity, period end	251,106	344,448	-27%	251,106	344,448	-27%
Trust Units (000s) ⁽²⁾	49,282	49,139	—	49,228	49,086	—
Operating						
Average daily production (boe/d)	8,591	8,313	3%	8,484	8,412	1%
Average price realizations (\$/boe)	50.57	41.44	22%	48.63	46.07	6%
Operating netback (\$/boe)	46.47	38.57	20%	43.54	42.64	2%

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

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

Message to Unitholders

I am pleased to report another quarter of solid performance for the Trust. In the fourth quarter of 2007, oil prices demonstrated unparalleled strength as global supply struggled to keep pace with demand growth. However, the Canadian dollar also strengthened significantly, reducing Canadian dollar realizations. Natural gas prices remained under pressure due to North American supply and demand imbalances. Within this environment, our operating netbacks remained strong, at \$46.47 per barrel of oil equivalent (boe), compared with \$38.57 per boe in the fourth quarter of 2006, while production rose 3% quarter over quarter. On a per Trust Unit basis, funds generated from operations rose 19% and net income increased 100%.

These strong quarterly results contributed to record cash flow for 2007 as funds generated from operations reached \$121.0 million (\$2.46 per Trust Unit). Net income for the year was reduced to a loss of \$1.2 million (\$0.02 per Trust Unit) reflecting a \$47.6 million future income tax expense related to the trust taxation legislation that takes effect in 2011. This provision was a non-cash expense relating to temporary differences between accounting versus tax rates and had no impact on our cash flows or our cash available for distribution.

Distributions in the fourth quarter totalled \$0.57 per Trust Unit (\$1.92 for the year), including an additional payment of \$0.12 per Trust Unit paid on December 15, 2007. The additional payment was due to increased income in 2007 as a result of high oil prices and higher production volumes in the fourth quarter stemming from royalty interest properties acquired during the third quarter.

RESERVES AND LAND VALUES

Our 2007 capital and acquisition program was successful in replacing 100% of our production for the year. We spent \$12.2 million on development activities, adding 0.6 million boe of net proved plus probable reserves at an average cost of \$14.38 per boe. In addition, we spent \$90.5 million on royalty acquisitions, acquiring 2.5 million boe of net proved plus probable reserves at an average cost of \$36.57 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 1.7.

At December 31, 2007, our land holdings encompassed nearly 2.4 million gross acres, up 15% from the previous year. Our undeveloped land, totalling 589,099 gross acres, was independently valued at \$30.3 million. The present value of our net proved plus probable oil and gas reserves, discounted at 10%, was \$711.6 million, contributing to a net asset value of \$11.99 per Trust Unit.

Since formation of the Trust in late 1996, operators leasing our royalty lands have drilled a total of 6,187 wells – activity that has helped to offset the depletion of our production and reserves – at no cost to us. This “free drilling” gives us the freedom to maintain a disciplined valuation approach to ensure that our acquisitions are accretive to present and future Unitholders.

HEALTHY DEVELOPMENT ACTIVITY CONTINUES ON OUR ROYALTY LANDS

Although drilling on our royalty lands declined 8% year over year, we fared better than industry in general, which experienced an overall 19% decline in drilling activity in 2007. And while drilling in unitized areas was down significantly, the decline in non-unitized drilling was a modest 5%. Considering the current industry slowdown, we are very encouraged by the tangible evidence of ongoing development potential on our royalty lands. There are currently 92 (4.1 equivalent net) licensed drilling locations on our royalty lands, compared with 119 (6.1 equivalent net) locations at this time last year. We are also seeing an increase in uphole recompletions in wells that have produced out in lower formations. We count among our active lessees some of the largest oil and gas producers in the industry. These companies have chosen certain of our royalty areas as key to their operations and we believe they will continue to be active in those areas.

OUTLOOK

Our distribution remains fixed at \$0.15 per month subject to quarterly review by our Board. Our distribution policy takes into consideration forecasted cash provided by operating activities, debt levels, and capital expenditures. 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.

As a result of acquisitions completed in the third quarter, our net debt at the end of the year was \$166.8 million, equal to about 1.4 times our 2007 cash flow from operating activities. We believe that having a strong balance sheet provides maximum flexibility for future transactions. Therefore, we plan to reduce debt as we are able with cash available after funding monthly distributions, reclamation fund contributions, and capital expenditures. We plan to invest \$10.6 million on development of our working interest properties in 2008, and with our recent acquisitions also contributing to our results, we expect production this year to average 8,200 boe per day.

Continued geopolitical uncertainty and strong global demand growth are expected to keep crude oil prices high, while storage levels and weather will be the key demand factors for natural gas prices.

In western Canada, drilling activity is anticipated to decline further in the short term in response to continued weakness in natural gas markets, high operating costs, and the strength of the Canadian dollar. As well, the new Alberta Crown royalty structure that takes effect next year could significantly change the economics of future exploration and development activities in the province. Already, a number of large exploration and production companies have announced reduced capital spending plans and scaled back drilling programs, especially in gas-prone areas of Alberta.

Most of Freehold's gas-prone lands are located in south-eastern Alberta and south-western Saskatchewan, where productivity per well is low, relative to other areas of the Western Canada Sedimentary Basin. In these areas, natural gas pricing has the most influence on producers' drilling decisions. A dramatic, prolonged reduction in industry drilling would likely be reflected on our royalty lands, but it is not possible to predict what the potential impact might be on Freehold's future production and reserves.

The Alberta Crown royalty changes will have 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, which is about 900 boe per day or 11% of our total production. Our royalty interest production in Alberta is not affected.

In October 2006, the federal government unexpectedly announced its plan to impose a tax on distributions from publicly-traded, specified income flow-through (SIFT) entities beginning January 1, 2011. In response to the SIFT tax changes, we continue to evaluate the options available to us, but in the interim we plan to retain the flow-through advantage of our trust structure unless there is a compelling reason for a faster transition to an alternative structure.

On February 26, 2008, the Minister of Finance delivered the federal government's 2008 budget. Rather than a flat provincial rate of 13% as previously announced, the budget proposes that the provincial component of the SIFT tax will be based on actual provincial corporate tax rates under the formula giving equal weight to province-by-province payrolls and revenues. This is a positive development for Alberta-based income trusts.

We remain committed to maximizing sustainable cash distributions over the long term by actively managing our large portfolio of oil and gas royalty interests, successfully developing our working interest properties to sustain production and extend reserve life, and acquiring appropriate assets to provide long-term growth in the value of the Trust. Going forward, we will continue to focus on the successful execution of this strategy.

On January 31, 2008, Tullio Cedraschi retired as President and CEO of the CN Investment Division. His successor, Russell J. Hiscock, will become one of the two Manager-appointed directors of Freehold at our Annual Meeting on May 7, 2008 to replace Mr. Cedraschi. We look forward to welcoming Mr. Hiscock as a director. The Board is pleased to announce that Mr. Cedraschi has agreed to stand for election at Freehold's Annual Meeting as an independent director.

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



David J. Sandmeyer
President and Chief Executive Officer

February 27, 2008

SUMMARY OF RESERVES

Our oil and gas reserves were independently evaluated by Trimble Engineering Associates Ltd. (Trimble) as at December 31, 2007. The evaluation was conducted in accordance with National Instrument 51-101 (NI 51-101), with reserves calculated on a net basis (our share of working interest properties minus royalties payable to others, plus royalties receivable on our royalty lands). Our Reserves Committee met with Trimble to review the findings and procedures, and the reserves report has been accepted by our Board. A summary of reserves, on a before-tax basis, is provided below. Complete NI 51-101 reserves disclosure, including after-tax reserve values, reserves by major property, and abandonment costs, will be included in our annual information form (AIF), which will be filed in March 2008.

Acquisitions and extensions replaced 100% of 2007 production, leaving net proved plus probable reserves unchanged at approximately 28 million boe. In 2007, reserves were assigned to 23,590 wells. Two thirds of our reserves are in the proved category, and 99% of our proved reserves are producing, which is high by industry standards. On a boe basis, our reserves profile is 37% natural gas, 5% natural gas liquids (NGL), 22% light and medium oil, and 36% heavy oil. Our reserve life index is 9.5 years, compared with 9.6 years at the end of 2006.

Under National Instrument 51-101, royalty interests cannot be included under gross reserves. Freehold is unique in that the majority of our assets are royalty interests, and this causes our gross reserves to be lower than our net reserves. This anomaly hinders an investor's ability to compare our reserves with others in our industry. We believe the most appropriate measure of reserves for Freehold is net reserves.

Oil and Gas Reserves as at December 31, 2007 ⁽¹⁾	Light and Medium Crude Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)
Proved										
Developed producing	2,074	4,230	1,350	6,238	5,638	40,438	266	937	4,629	18,144
Developed non-producing	0	0	0	0	104	79	3	2	20	15
Undeveloped	0	0	0	135	0	145	0	0	0	159
Total proved	2,074	4,230	1,350	6,373	5,742	40,662	269	939	4,649	18,318
Probable	736	1,899	651	3,837	2,969	20,719	134	455	2,016	9,645
Total proved plus probable	2,810	6,129	2,001	10,210	8,711	61,381	403	1,394	6,665	27,963

(1) Columns may not add due to rounding

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

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

Total Future Net Revenue (undiscounted) as at December 31, 2007 Forecast Prices and Costs (\$000s)	Reserves Category	
	Proved	Proved Plus Probable
Royalty Income	797,803	1,320,480
Revenue from Working Interest Properties	356,533	528,280
Royalty expense on Working Interest Properties	(22,618)	(39,339)
Operating costs	(109,442)	(161,334)
Development costs	(576)	(4,271)
Well abandonment and reclamation costs	(7,267)	(8,506)
Future net revenue before income taxes	1,014,433	1,635,310
Future income taxes	(201,283)	(358,076)
Future net revenue after income taxes	813,150	1,277,234

Reserve Life Index ⁽¹⁾	Proved	Total	Proved Plus
	Producing	Proved	Probable
Net reserves (Mboe)	18,144	18,318	27,963
Net production (Mboe)	2,560	2,587	2,932
Reserve life index (years)	7.1	7.1	9.5

(1) Calculated by dividing the Trimble forecast of 2008 net production into the remaining net reserves.

Net Present Value ^{(1) (2)}	Before tax, discounted at			
	0%	5%	10%	15%
(\$000s)				
Proved				
Developed producing	1,004,362	675,806	523,299	434,964
Developed non-producing	439	386	343	307
Undeveloped	9,632	7,013	5,713	4,936
Total proved	1,014,433	683,205	529,355	440,207
Probable	620,878	290,017	182,269	132,936
Proved plus probable	1,635,311	973,222	711,624	573,143

(1) Columns may not add due to rounding.

(2) Forecast prices and costs, before tax. Based on the December 31, 2007 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

Reconciliation of Oil and Gas Reserves (1) (Mboe)	Proved		Probable		Proved Plus Probable	
	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾	Gross ⁽²⁾	Net ⁽³⁾
December 31, 2006	5,275	18,722	1,867	9,290	7,142	28,012
Extensions	81	329	86	288	167	616
Improved recovery	—	—	—	—	—	—
Technical revisions	124	684	71	(681)	195	3
Discoveries	—	—	—	—	—	—
Acquisitions	—	1,696	—	778	—	2,473
Dispositions	—	—	—	—	—	—
Economic factors	32	30	18	15	49	45
Production ⁽⁴⁾	(862)	(3,142)	(26)	(44)	(888)	(3,186)
December 31, 2007	4,650	18,318	2,016	9,646	6,665	27,963
Change over prior year	(625)	(404)	149	356	(477)	(49)

(1) Numbers may not add due to rounding.

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

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

(4) Production estimated by Trimble.

ACQUISITION AND DEVELOPMENT COSTS

Analysis of Development and Acquisition Costs, Net Reserves	2007	2006	2005	Three-Year Results
Development expenditures (\$000s)	12,167	11,446	7,982	31,595
Change in future development capital estimates (\$000s)	(3,305)	(2,549)	235	(5,619)
Net reserve additions by development (Mboe)	616	1,146	945	2,708
Development costs (\$/boe)⁽¹⁾	14.38	7.76	8.70	9.59
Acquisition expenditures (\$000s)	90,456	5,382	351,705	447,543
Net reserve additions by acquisition (Mboe)	2,473	376	12,889	15,738
Acquisition costs (\$/boe)	36.57	14.33	27.29	28.44
Total expenditures (\$000s)	102,623	16,828	359,687	479,138
Change in future development capital estimates (\$000s)	(3,305)	(2,549)	235	(5,619)
Net reserve additions (Mboe)	3,090	1,522	13,834	18,445
Development and acquisition costs (\$/boe)	32.15	9.38	26.02	25.67

(1) Development expenditures plus change in future capital, divided by reserves added.

Recycle Statistics, Net Reserves (\$ per boe, except as noted)	2007	2006	2005	Three-Year Results
Operating netback ⁽¹⁾⁽⁴⁾	43.63	42.64	45.49	43.87
Development and acquisition costs ⁽²⁾⁽⁴⁾	32.15	9.38	26.02	25.67
Recycle ratio (times) ⁽³⁾	1.4	4.5	1.8	1.7

(1) Total revenue, less operating costs and royalty expenses (net of Alberta Royalty Credit in 2005 and 2006).

(2) Development expenditures, plus change in future capital, plus acquisition costs; divided by net reserves added through development and acquisition activities.

(3) Operating netback divided by the average cost of acquiring and developing new reserves.

(4) Operating netback is based on gross production, while development and acquisition costs are based on net reserves.

SUMMARY OF LAND HOLDINGS

At December 31, 2007, our land holdings encompassed approximately 2.4 million gross acres, more than 90% of which are royalty interests.

Summary of Land Holdings (gross acres) ⁽¹⁾	December 31, 2007		December 31, 2006	
	Total	Undeveloped	Total	Undeveloped
Mineral title lands ⁽²⁾	549,758	160,034	550,636	164,199
Gross overriding royalty (GORR) lands ⁽³⁾	1,526,878	360,832	1,218,700	365,381
Royalty assumption lands ⁽⁴⁾	96,072	19,648	96,082	19,620
Total royalty lands	2,172,708	540,514	1,865,418	549,200
Working interest properties	207,428	48,585	203,952	49,035
Total land holdings	2,380,136	589,099	2,069,370	598,235

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

(2) The royalties received from the sale of oil, natural gas and potash produced from the leased mineral title lands are determined by the individual lease agreements. Mineral title lands are held in perpetuity.

(3) Gross overriding royalty lands consist of properties owned by a number of third party oil and gas companies in respect of which varying royalties or net profits interests have been reserved to Freehold.

(4) Mineral title properties owned by a number of third party oil and gas companies in respect of which gross overriding royalties varying from 4.7% to 6.5% have been reserved to Freehold.

Acquisitions during 2007 increased land holdings by 15%. Approximately 63% of our land is in Alberta, 21% is in Saskatchewan, 12% is in Ontario, and 3% is in British Columbia.

Land Holdings by Province (gross acres) ⁽¹⁾	As at December 31		
	2007	2006	Change
Alberta	1,488,098	1,218,097	22%
Saskatchewan	505,223	464,977	9%
Ontario	296,109	296,109	—
British Columbia	82,423	81,904	1%
Manitoba	8,283	8,283	—
Total	2,380,136	2,069,370	15%

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

NET ASSET VALUE

At December 31, 2007, the present value of our net proved plus probable oil and gas reserves, discounted at 10%, before tax, was \$711.6 million, up from \$636.3 million one year ago. The improvement came from reserve additions of 3.1 million boe during the year and higher forecast prices at the end of 2007. Our net asset value was \$11.99 per Trust Unit, up from \$11.74 at the end of 2007. In addition to the increase in the value of oil and gas reserves, the major changes year over year were a \$78 million increase in bank debt, a \$10.9 million increase in the value of undeveloped land, and a \$3.8 million increase in the value of potash reserves.

Net Asset Value as at December 31, 2007 ⁽¹⁾ (\$000s, except unit data)	Before tax, discounted at			
	0%	5%	10%	15%
Present value of oil and gas reserves ⁽²⁾	1,635,310	973,222	711,624	573,143
Present value of potash reserves ⁽³⁾	62,261	25,648	14,317	9,753
Undeveloped land ⁽⁴⁾	30,252	30,252	30,252	30,252
Reclamation fund	1,788	1,788	1,788	1,788
Working capital	11,219	11,219	11,219	11,219
Bank debt	(178,000)	(178,000)	(178,000)	(178,000)
Net asset value	1,562,830	864,129	591,200	448,155
Trust Units outstanding	49,316,813	49,316,813	49,316,813	49,316,813
Net asset value per Trust Unit	31.69	17.52	11.99	9.09

(1) Columns may not add due to rounding.

(2) Based on net proved plus probable reserves evaluated by Trimble.

(3) Potash reserves, evaluated by Rife Resources Ltd., are not subject to NI 51-101.

(4) Evaluated by Seaton-Jordan & Associates Ltd., effective December 31, 2007.

Management's Discussion and Analysis (MD&A)

The following discussion is management's opinion about the operating and financial results of Freehold Resources Ltd., Petrovera Resources (a general partnership), and Freehold Royalty Trust (collectively, Freehold or the Trust), for the three months ended December 31, 2007 and previous periods, and the outlook for Freehold based on information available as at February 27, 2008. The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the quarters ended December 31, 2007 and December 31, 2006, and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion should be read in conjunction with the Trust's annual MD&A and audited financial statements for the years ended December 31, 2006 and 2005, together with the accompanying notes. These are on pages 13 through 49 of the Trust's 2006 annual report to Unitholders.

FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at February 27, 2008, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, taxation, royalties, regulation, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility, and our ability to access sufficient capital from internal and external sources. Risks are described in more detail in our Annual Information Form, which is available on our website. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. Except as required by law, we do not undertake to update these forward-looking statements.

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

NON-GAAP MEASURES

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

Operating 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. Funds generated from operations is a key measure of our ability to generate cash, finance operations, and pay monthly distributions. Funds generated from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds generated from operations throughout this report are based on cash provided by operating activities before changes in non-cash working capital as per the Statement of Cash Flows. Funds generated from operations per Trust Unit is calculated based on the weighted average number of Trust Units outstanding consistent with the calculation of net income per Trust Unit.

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

THE ROYALTY ADVANTAGE

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 following table demonstrates the advantage of our royalty lands from which we receive revenue but do not incur royalty expenses, operating expenses, site restoration expenses, or capital expenditures.

Components of Distributions to Unitholders			
Year ended December 31, 2007 ⁽¹⁾	Royalty Interest	Working Interest	Total Trust
(\$000s)	Lands	Properties	
Gross revenue	101,976	50,208	152,184
Royalty expense	—	(5,003)	(5,003)
Freehold mineral tax	(1,008)	(252)	(1,260)
Net revenue	100,968	44,953	145,921
Operating expense	—	(11,076)	(11,076)
	100,968	33,877	134,845
General and administrative expense	(4,782)	(1,703)	(6,485)
Interest expense	(6,408)	(597)	(7,005)
Income and capital taxes	—	(179)	(179)
Unit based compensation	433	198	631
Expenditures on reclamation	—	(799)	(799)
Funds generated from operations	90,211	30,797	121,008
Reclamation fund withdrawal	—	329	329
Capital expenditures	—	(12,167)	(12,167)
Acquisitions	(90,456)	—	(90,456)
Changes in debt	74,834	3,166	78,000
Changes in working capital	(1,489)	(680)	(2,169)
Distributions declared	73,100	21,445	94,545

(1) Numbers may not add due to rounding.

DEVELOPMENT ACTIVITIES

Industry activity in western Canada declined 23% in the fourth quarter with 1,500 fewer wells drilled than in the fourth quarter last year. Overall, industry drilled 3,000 fewer wells in 2007, a decline of 19% year over year. The majority of the decline was in gas prone regions, areas hurt by continued weakness in natural gas prices. Industry forecasters are predicting the slowdown to continue through 2008, with drilling expected to drop by 22% to 14,425 wells this year.

ROYALTY INTEREST LANDS

Our royalty lands are comprised of a large and widely diversified portfolio of properties extending from north-eastern British Columbia to Ontario, including interests in 346 production units that provide small royalty interests in more than 14,500 wells. Overall, on a gross basis, drilling on our royalty lands generally mirrors industry activity levels.

Drilling on Freehold's non-unitized lands was up 15% year over year, with fourth quarter activity up 57%. Activity on the newly acquired properties aided in the growth of non-unitized drilling. There are currently 92 (4.1 equivalent net) licensed drilling locations on our royalty lands, compared with 119 (6.1 equivalent net) locations at this time last year. We are also seeing uphole recompletions in wells that have produced out in lower formations, which is positive to the long-term sustainability of the Trust.

Overall, on an equivalent net basis drilling was down 9% quarter over quarter and down 8% year over year as a result of reduced activity on unitized lands.

Royalty Interest Lands Drilling Summary	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
Unitized wells						
Gross	31	189	-84%	266	471	-44%
Equivalent net ⁽¹⁾	0.0	0.5	-100%	0.8	1.5	-47%
Non-unitized wells						
Gross	105	67	57%	354	307	15%
Equivalent net ⁽¹⁾	3.9	3.8	3%	16.4	17.2	-5%
Total						
Gross	136	256	-47%	620	778	-20%
Equivalent net ⁽¹⁾	3.9	4.3	-9%	17.2	18.7	-8%

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

WORKING INTEREST PROPERTIES

On a net basis, drilling on our working interest lands was 17% higher quarter over quarter. The majority of drilling during the fourth quarter was targeted to oil development projects at Hayter and Southeast Saskatchewan.

Working Interest Properties Drilling Summary	Three Months Ended December 31				Year Ended December 31			
	2007		2006		2007		2006	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Oil	9	2.1	8	1.5	30	8.1	36	6.3
Natural gas	—	—	2	0.2	24	0.6	32	0.9
Other	—	—	1	0.1	—	—	5	0.3
Total	9	2.1	11	1.8	54	8.7	73	7.5

RESULTS OF OPERATIONS

PRODUCTION

Production volumes increased 3% quarter over quarter. Royalty interests contributed 70% of total volumes produced during the quarter. Royalty interest production declined 8% quarter over quarter due to the reclassification upon payout of two royalty wells in Northeast British Columbia to working interest status and, to a lesser extent, due to reduced industry drilling, partly offset by royalty acquisitions in the third quarter, which added 675 boe per day in the fourth quarter. Working interest production rose 44% on drilling successes at Hayter and Southeast Saskatchewan and the well reclassification mentioned above.

On a boe basis, our production profile for the year ended December 31, 2007 was 36% natural gas, 4% NGL, 23% light and medium oil, and 37% heavy oil.

Successful drilling on our working interest properties and royalty acquisitions in the third quarter kept production for the year level with 2006, which was 7% above our initial forecast for 2007. Based on our estimates of decline rates and capital development programs, we are currently forecasting average production in 2008 of about 8,200 boe per day.

Average Daily Production	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
Royalty lands						
Oil (bbls/d)	3,328	3,394	-2%	3,188	3,456	-8%
NGL (bbls/d)	203	301	-33%	252	297	-15%
Natural gas (Mcf/d)	15,055	17,084	-12%	14,310	16,660	-14%
Oil equivalent (boe/d)	6,040	6,542	-8%	5,825	6,530	-11%
Working interest properties						
Oil (bbls/d)	1,907	1,595	20%	1,846	1,409	31%
NGL (bbls/d)	58	37	57%	81	61	33%
Natural gas (Mcf/d)	3,517	834	322%	4,393	2,478	77%
Oil equivalent (boe/d)	2,551	1,771	44%	2,659	1,882	41%
Total Trust						
Oil (bbls/d)	5,235	4,989	5%	5,034	4,865	3%
NGL (bbls/d)	261	338	-23%	333	358	-7%
Natural gas (Mcf/d)	18,572	17,918	4%	18,703	19,138	-2%
Oil equivalent (boe/d)	8,591	8,313	3%	8,484	8,412	1%
Number of days in period (days)	92	92	—	365	365	—
Total volumes during period (Mboe)	790	765	3%	3,097	3,070	1%
Potash production (tonnes/d)	15.4	13.8	12%	14.2	10.5	35%

BENCHMARK PRICES

West Texas Intermediate (WTI) crude oil prices rose dramatically quarter over quarter, while the U.S. dollar continued to lose value. Edmonton Par prices also rose, but to a lesser extent due to the relative strength of the Canadian dollar. Lack of refining capacity for heavier grades of crude caused the price spread between light and heavy oil to widen. As a result, Bow River/Hardisty prices rose only 25% quarter over quarter compared with the 50% rise in WTI and the 34% rise in Edmonton Par.

AECO natural gas prices declined 6% quarter over quarter. Liquefied natural gas imports and elevated levels of natural gas drilling in the United States have kept the North American market well supplied. The level of natural gas in storage remains above the five-year average, causing continued price uncertainty in natural gas markets.

For the full year, benchmark oil prices were higher, while natural gas prices were down 5% from 2006. Continued geopolitical uncertainty and strong global demand growth are expected to keep crude oil prices high, while storage levels and weather will be the key demand factors for natural gas prices.

Average Benchmark Prices	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
WTI crude oil (US\$/bbl)	90.68	60.26	50%	72.31	66.22	9%
US\$/Cdn\$ exchange rate	1.0188	0.8878	15%	0.9352	0.8818	6%
Edmonton Par crude oil (Cdn\$/bbl)	86.42	64.48	34%	76.35	72.77	5%
Light/heavy oil differential (Cdn\$/bbl)	29.37	18.80	56%	22.83	21.23	8%
Bow River/Hardisty (Cdn\$/bbl)	57.05	45.69	25%	53.52	51.53	4%
AECO natural gas (Cdn\$/Mcf)	6.00	6.36	-6%	6.61	6.98	-5%

Source for commodity prices: Canadian Association of Petroleum Producers.

REALIZED PRICES

Freehold's average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average price realizations were 22% higher in the fourth quarter of 2007 and 6% higher for the year. As approximately 37% of our total production mix is heavy oil, the markets for heavy oil are of particular relevance for us, and prices for the benchmark Bow River/Hardisty stream are generally a close proxy for our average oil realizations.

Average Selling Prices	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
Oil (\$/bbl)	58.93	44.34	33%	54.38	50.24	8%
NGL (\$/bbl)	50.85	39.25	30%	53.53	50.29	6%
Oil and NGL (\$/bbl)	58.55	44.01	33%	54.33	50.25	8%
Natural gas (\$/Mcf)	6.07	6.14	-1%	6.47	6.54	-1%
Oil equivalent (\$/boe)	50.57	41.44	22%	48.63	46.07	6%
Potash (\$/tonne)	229.49	228.84	—	225.28	220.13	2%

REVENUE

Gross revenue in the fourth quarter increased 26% on higher oil prices and production volumes. For the year ended December 31, 2007, gross revenue was up 6%.

The accompanying table demonstrates the net effect of price and volume variances on gross revenues. In the fourth quarter, approximately 84% of the increase was due to higher oil prices. Year over year, 80% of the increase related to higher prices, and 20% was due to volume increases.

Gross Revenue Variances (\$000s)	Three Months Ended		Year Ended	
	December 31		December 31	
	2007 vs. 2006	2006 vs. 2005	2007 vs. 2006	2006 vs. 2005
Oil and NGL				
Production increase (decrease)	913	(123)	2,872	7,149
Price increase (decrease)	7,124	(1,310)	7,776	5,844
Net increase (decrease)	8,037	(1,433)	10,648	12,993
Natural gas				
Production increase (decrease)	365	(1,341)	(1,028)	5,531
Price increase (decrease)	(125)	(9,708)	(486)	(12,322)
Net increase (decrease)	240	(11,049)	(1,514)	(6,791)
Other ⁽¹⁾	20	141	(17)	(49)
Gross revenue increase (decrease)	8,297	(12,341)	9,117	6,153

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

Net revenue improved 23% quarter over quarter and 5% year over year. Royalty and freehold mineral tax expenses rose significantly in 2007, largely due to the increase in working interest production, which increased 44% quarter over quarter and 41% year over year. Royalty expenses are incurred only on our working interest properties. As well, the Alberta Royalty Credit was discontinued in 2007.

Net Revenue	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
Gross revenue	40,511	32,214	26%	152,184	143,067	6%
Royalty and freehold mineral tax expense ⁽¹⁾	(1,293)	(449)	188%	(6,263)	(3,831)	63%
Net revenue	39,218	31,765	23%	145,921	139,236	5%

(1) Royalty expenses and freehold mineral tax include all Crown charges and royalty payments to third parties and are net of the Alberta Royalty Credit in 2006.

EXPENSES

ROYALTY EXPENSE AND FREEHOLD MINERAL TAX

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 production volumes. In the fourth quarter, royalty expense on our working interest properties more than doubled due to higher oil prices and higher working interest production.

The majority of our freehold mineral taxes, payable annually to the Crown, pertain to two sections of land in the Hayter area that were acquired in the Petrovera acquisition in May 2005. Development activity on these lands has resulted in increased production and higher property values. Prior to the Petrovera acquisition, our freehold mineral taxes were not material and were recorded under working interest expenses.

Royalty expenses rose 63% year over year due to higher freehold mineral taxes, discontinuation of the Alberta Royalty Credit program, and higher working interest production in 2007. As well, royalty expense in 2007 included approximately \$250,000 in freehold mineral taxes that related to 2006.

Royalty Expense and Freehold Mineral Tax ⁽¹⁾ (net of Alberta Royalty Credit) ⁽²⁾	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
Working interest properties (\$000s)	1,297	351	270%	5,255	3,447	52%
Per boe (\$)	5.53	2.15	157%	5.41	5.02	8%
Royalty interest lands (\$000s)	(4)	98	-104%	1,008	384	163%
Per boe (\$)	(0.01)	0.16	-106%	0.47	0.16	194%
Total Trust (\$000s)	1,293	449	188%	6,263	3,831	63%
Per boe (\$)	1.64	0.59	178%	2.02	1.25	62%

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

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

OPERATING EXPENSES

A percentage of operating costs is fixed and, as such, per boe operating costs are highly variable to production volumes. On working interest properties, operating costs per boe declined 24% in the fourth quarter because of higher production. On a total Trust basis, operating costs per boe were 6% higher. The increase was primarily attributable to a higher proportionate share of working interest volumes during the quarter, as we do not incur operating costs on our royalty interest production. Operating costs for the year averaged \$3.58 per boe, up 32% from 2006 but in line with our expectations. Operating costs are forecast to average \$3.85 per boe in 2008.

Operating Expenses	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
Working interest properties (\$000s)	2,479	2,259	10%	11,076	8,309	33%
Per boe (\$)	10.56	13.86	-24%	11.41	12.09	-6%
Royalty interest lands ⁽¹⁾ (\$000s)	—	—	—	—	—	—
Per boe (\$)	—	—	—	—	—	—
Total operating expenses (\$000s)	2,479	2,259	10%	11,076	8,309	33%
Total Trust (\$/boe)	3.14	2.95	6%	3.58	2.71	32%

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

DEPLETION AND DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION

Depletion of oil and natural gas properties (including the capitalized portion of the asset retirement obligation) and depreciation of equipment are provided for on a unit-of-production basis using estimated proved reserves. For the first three quarters of 2007, the estimate of proved reserves was based on the independent evaluation dated December 31, 2006, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2007.

Depletion, Depreciation and Accretion Expenses (\$000s, except as noted)	Year Ended December 31		
	2007	2006	Change
Depletion and depreciation	72,400	71,874	1%
Accretion of asset retirement obligation	266	257	4%
Total depletion, depreciation and accretion expenses	72,666	72,131	1%
Per boe (\$)	23.47	23.50	—

GENERAL AND ADMINISTRATIVE EXPENSES (G&A)

In the fourth quarter of 2007, G&A expenses totalled \$1.7 million, including \$0.9 million charged by the Manager for time and direct costs incurred on behalf of the Trust. On a per boe basis, G&A expenses were 52% higher quarter over quarter and 16% higher year over year. The rise in G&A costs reflects higher staff levels and general inflationary pressures in Calgary, including a tight employment market that has increased compensation for the Manager’s staff. G&A costs are forecast to average \$2.44 per boe in 2008.

Fourth quarter expenses also reflect higher deferred compensation expenses. In the fourth quarter, we recorded a non-cash expense of \$17,000 (2006 – \$6,000), with a corresponding increase to contributed surplus, as unit based compensation relating to the deferred trust unit plan to non-management directors. The total for the year ended December 31, 2007 was \$265,000 (2006 – \$247,000). We also recorded a non-cash expense of \$225,000 (2006 – recovered \$130,000) in the fourth quarter for the Trust’s proportionate share of the Manager’s long-term incentive plan for 2007. The total for the year ended December 31, 2007 was \$366,000 (2006 – \$43,000). As at December 31, 2007, we had recorded \$697,000 as a deferred long-term compensation asset and accrued \$1,106,000 as a long-term liability.

G&A Expenses	Three Months Ended December 31			Year Ended December 31		
	2007	2006	Change	2007	2006	Change
G&A expenses (\$000s)	1,667	1,100	52%	6,485	5,581	16%
Per boe (\$)	2.11	1.44	47%	2.09	1.82	15%
As a percentage of revenue	4.1%	3.4%	21%	4.3%	3.9%	10%

MANAGEMENT FEES

The quarterly management fee, which is paid in Trust Units, was 35,654 Trust Units for the fourth quarter of 2007, unchanged from 2006. The ascribed value was 5% higher due to a higher Trust Unit price at the end of the fourth quarter of 2007.

Management Fees (Paid in Trust Units)	Three Months Ended December 31			Year Ended December 31		
	2007	2006	Change	2007	2006	Change
Trust Units issued in payment of management fees	35,654	35,654	—	142,616	142,616	—
Ascribed value (\$000s) ⁽¹⁾	556	528	5%	2,130	2,649	-20%
Per boe (\$)	0.70	0.69	1%	0.69	0.86	-20%

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

INTEREST EXPENSES

Interest expenses increased 88% quarter over quarter, due to increased debt used to fund two acquisitions and higher effective interest rates.

Interest Expenses (\$000s, except as noted)	Three Months Ended December 31			Year Ended December 31		
	2007	2006	Change	2007	2006	Change
	Net interest expense	2,554	1,358	88%	7,005	5,194
Per boe (\$)	3.23	1.78	81%	2.26	1.69	34%

OPERATING NETBACK

In the fourth quarter of 2007, our operating netback was \$46.47 per boe, up 20% mainly due to higher oil prices, partly offset by a higher proportion of working interest production with associated royalty and operating expenses. We did not hedge any of our production during 2007. This policy is subject to review by our Board.

Operating Netback (\$/boe)	Three Months Ended December 31			Year Ended December 31		
	2007	2006	Change	2007	2006	Change
	Gross revenue ⁽¹⁾	51.25	42.11	22%	49.14	46.60
Royalty and freehold mineral tax expense ⁽²⁾	1.64	0.59	178%	2.02	1.25	62%
Operating expenses	3.14	2.95	6%	3.58	2.71	32%
Operating netback	46.47	38.57	20%	43.54	42.64	2%

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

(2) Royalty expenses and freehold mineral tax include all Crown charges and royalty payments to third parties and are net of the Alberta Royalty Credit in 2006.

FUNDS GENERATED FROM OPERATIONS AND NET INCOME

Funds generated from operations totalled \$32.6 million (\$0.66 per Trust Unit), up 19% from the fourth quarter last year, reflecting higher oil prices and production. For the year, funds generated from operations increased 1% to \$121.0 million (\$2.46 per Trust Unit).

Net income for the fourth quarter rose 100% to \$19.1 million. A future income tax recovery resulted in a \$5.9 million increase to net income quarter over quarter. In December 2007, the federal government substantively enacted tax rate reductions, which lowered the corporate tax rates for 2008 to 20.5% with further yearly reductions to an ultimate rate of 15% in 2012 and future years. These rate reductions also lower the trust taxation rate (as enacted by the federal government in the second quarter of 2007 for years commencing in 2011) from 31.5% to 29.5% in 2011 and to 28% in 2012 and future years.

For the year, net income was reduced to a loss of \$1.2 million (\$(0.02) per Trust Unit) with the recording of a non-cash future income tax expense in the second quarter related to the substantive enactment of the trust taxation legislation, offset somewhat by the future income tax recovery in the fourth quarter.

Funds Generated From Operations and Net Income	Three Months Ended December 31			Year Ended December 31		
	2007	2006	Change	2007	2006	Change
	Cash provided by operating activities	32,503	26,437	23%	119,641	130,835
Changes in non-cash working capital	88	957	-91%	1,367	(10,986)	-112%
Funds generated from operations (\$000s)	32,591	27,394	19%	121,008	119,849	1%
Per Trust Unit (\$)	0.66	0.56	18%	2.46	2.44	1%
Net income (loss) (\$000s)	19,067	9,545	100%	(1,192)	45,181	-103%
Per Trust Unit, basic and diluted (\$)	0.39	0.19	105%	(0.02)	0.92	-102%

DISTRIBUTIONS

Distributions to Unitholders totalled \$0.57 per Trust Unit for the fourth quarter. Royalty income contributed 77% of distributions for the year. Since inception, the Trust has distributed \$580.7 million (\$16.22 per Trust Unit) to Unitholders.

Accumulated Distributions (\$000s, except as noted)	Three Months Ended December 31		Year Ended December 31	
	2007	2006	2007	2006
Distributions to Unitholders	28,096	23,594	94,545	103,100
Accumulated, beginning of period	552,573	462,530	486,124	383,024
Accumulated, end of period	580,669	486,124	580,669	486,124
Distributions per Trust Unit (\$)⁽¹⁾	0.57	0.48	1.92	2.10
Accumulated, beginning of period	15.65	13.82	14.30	12.20
Accumulated, end of period	16.22	14.30	16.22	14.30

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

The following table illustrates the relationship between cash provided from operating activities and historical distributions, as well as net income (loss) and historical distributions. Net income includes significant non-cash charges that do not affect cash flow. In 2007, these charges amounted to \$13.6 million for the fourth quarter and \$123.0 million for the year. Net earnings also include fluctuations in future income taxes due to changes in tax rates and tax rules. In addition, other non-cash charges, such as depletion and depreciation on property, plant and equipment and accretion on the asset retirement obligations, 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)	Three Months Ended December 31		Year Ended December 31	
	2007	2006	2007	2006
Cash provided by operating activities	32,503	26,437	119,641	130,835
Net income (loss)	19,067	9,545	(1,192)	45,181
Cash distributions paid or payable	28,096	23,594	94,545	103,100
Excess of cash provided by operating activities over cash distributions	16%	12%	27%	27%
Excess (shortfall) of net income over cash distributions	(32%)	(60%)	(101%)	(56%)

DISTRIBUTION POLICY

The regularly monthly distribution is currently fixed at \$0.15 per Trust Unit. Our distribution policy takes into consideration forecasted cash provided by operating activities, debt levels, and capital expenditures. 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.

2008 Key Operating Assumptions	February 27 2008
Average daily production (boe/d)	8,200
Average WTI oil price (US\$/bbl)	85.00
Average light/heavy oil price differential (Cdn\$/bbl)	25.00
Average Bow River Hardisty oil price (Cdn\$/bbl)	60.00
Average AECO natural gas price (Cdn\$/Mcf)	6.65
Average exchange rate (Cdn\$/US\$)	1.00
Average operating costs (\$/boe)	3.85
Average general and administrative costs (\$/boe)	2.44
Capital expenditures (\$ millions)	10.6
Long-term debt at year end (\$ millions)	155
Weighted average Trust Units outstanding (thousands)	49,371
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 37% of our total boe production is heavy oil. Supply and demand imbalances could keep heavy oil price differentials well above historical averages. We will continue to monitor prices and activity levels closely, and our guidance will be reviewed and updated quarterly.

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

2008 Sensitivity Analysis	Change (+/-)	Estimated Change in Distributions to Unitholders	
		(\$000s)	(\$/Trust Unit)
WTI crude oil price	US\$1.00/bbl	1,989	0.04
Light/heavy oil price differential	Cdn\$1.00/bbl	1,796	0.04
Natural gas price	Cdn\$0.25/Mcf	1,657	0.03
Exchange rate (US\$/Cdn\$)	0.01	1,392	0.03
Interest rates	1%	988	0.02
Oil and NGL production	100 bbls/d	1,584	0.03
Natural gas production	1,000 Mcf/d	2,557	0.05

QUARTERLY PERFORMANCE SUMMARY

Our results are directly influenced by commodity prices, which are determined by supply and demand factors, weather, seasonality, global political events, general economic conditions, and changes in Canadian/U.S. dollar exchange rates. Quarterly variances in revenues, net income, 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 the Trust's financial results.

- 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 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. Both acquisitions were funded through Freehold's credit facilities, which were increased to \$210 million. The acquisitions contributed approximately 675 boe per day in the fourth quarter of 2007.
- During 2007, the Canadian dollar strengthened considerably relative to the U.S. dollar, which influenced our Canadian dollar price realizations for crude oil.
- In the last half of 2007, WTI crude prices rose significantly, reaching record highs in the fourth quarter. This significant rise in benchmark pricing boosted our revenues; however, the revenue increase was mitigated somewhat by the higher Canadian dollar.
- Over the past several quarters we have experienced higher operating expenses on our working interest properties, which currently comprise about 30% of our total production volumes. Rising costs have been experienced industry wide and particularly in Alberta where strong economic growth and oil sands development have created increased demand for people and services. However, the effect of higher costs on our overall results is mitigated by our large proportion of royalty interest production, which is unencumbered by operating expenses.
- 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 79% of total boe production.

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

Quarterly Review	2007				2006			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Financial (\$000s, except as noted)								
Revenue, net of royalty expense	39,218	36,086	35,907	34,988	31,765	36,550	36,998	33,923
Funds generated from operations	32,591	29,907	30,213	28,297	27,394	31,692	32,565	28,198
Per Trust Unit (\$)	0.66	0.61	0.61	0.58	0.56	0.65	0.66	0.58
Distributions to Unitholders	28,096	22,165	22,151	22,133	23,594	26,521	26,502	26,483
Per Trust Unit (\$) ⁽¹⁾	0.57	0.45	0.45	0.45	0.48	0.54	0.54	0.54
Payout ratio (%)	86	74	73	78	86	84	81	94
Net income (loss)	19,067	12,487	(42,533)	9,787	9,545	12,728	14,142	8,766
Per Trust Unit, basic and diluted (\$)	0.39	0.25	(0.86)	0.20	0.19	0.26	0.29	0.18
Property and royalty acquisitions	26	90,430	—	—	—	5,382	—	—
Capital expenditures	3,901	1,960	2,830	3,476	3,766	4,649	1,430	1,601
Long-term debt	178,000	179,000	100,000	99,000	100,000	98,000	96,000	105,000
Trust Units outstanding								
Weighted average (000s)	49,282	49,246	49,210	49,175	49,139	49,103	49,068	49,032
At quarter end (000s)	49,317	49,281	49,246	49,210	49,174	49,139	49,103	49,067
Operating (\$/boe, except as noted)								
Daily production (boe/d)	8,591	8,219	8,566	8,564	8,313	8,335	8,212	8,794
Royalty interest production (%)	70	69	63	72	79	77	79	76
Average selling price	50.57	48.28	48.21	47.40	41.44	48.95	50.27	43.78
Operating netback	46.47	43.65	42.28	42.06	38.57	44.92	47.08	40.18
Operating expenses	3.14	4.07	3.79	3.33	2.95	2.75	2.43	2.68
Working Interest properties	10.56	13.17	10.34	11.82	13.86	11.88	11.51	11.26
General and administrative expenses	2.11	1.35	1.67	3.24	1.44	1.32	1.79	2.69
Benchmark Prices								
WTI crude oil (US\$/bbl)	90.68	75.38	65.04	58.16	60.26	70.48	70.70	63.45
Exchange rate (Cdn\$/US\$)	1.02	0.96	0.91	0.85	0.89	0.89	0.89	0.87
Edmonton Par crude oil (Cdn\$)	86.42	79.95	71.93	67.09	64.48	79.08	78.55	68.96
Light/heavy oil differential (Cdn\$/bbl)	29.37	23.95	21.02	16.98	18.80	20.14	17.43	28.57
Bow River/Hardisty (Cdn\$/bbl)	57.05	56.00	50.91	50.11	45.69	58.94	61.11	40.39
AECO natural gas (Cdn\$/Mcf)	6.00	5.61	7.37	7.45	6.36	6.03	6.27	9.27
Unit Trading Performance								
High (\$)	15.85	15.85	15.85	15.30	19.80	23.06	21.70	22.20
Low (\$)	14.46	12.51	13.77	13.00	12.43	18.50	18.02	18.44
Close (\$)	15.60	15.26	14.53	14.35	14.81	19.00	21.00	19.50
Volume (000s)	7,036	5,172	6,853	6,040	13,867	5,153	5,336	11,155

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

LIQUIDITY AND CAPITAL RESOURCES

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. Capital expenditures on working interest properties totalled \$3.9 million in the fourth quarter (\$12.2 million for the year). In total, we spent \$6.0 million in Southeast Saskatchewan, \$3.7 million at Hayter, and the remainder on various projects in Alberta. Capital expenditures in 2008 are anticipated to be \$10.6 million, the majority of which will be spent at Hayter and Southeast Saskatchewan.

In the third quarter, we acquired certain overriding royalty interests in Alberta and Saskatchewan for \$90.5 million. Both acquisitions were funded through Freehold's credit facilities.

Acquisitions and Capital Expenditures (\$000s, except as noted)	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
Property and royalty acquisitions (net)	26	—	—	90,456	5,382	1581%
Capital expenditures	3,901	3,766	4%	12,167	11,446	6%
Change in reclamation fund	31	15	107%	(329)	153	-315%
	3,958	3,781	5%	102,294	16,981	502%

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, the 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.

During the third quarter of 2007, we increased our credit facility by \$45 million to \$210 million. All other terms, including interest rates and security of the facilities, remain unchanged.

At December 31, 2007, we had no short-term debt outstanding and long-term debt was \$178 million. We had positive working capital of \$11.2 million, resulting in net debt of \$166.8 million. In addition, we had accrued \$1.1 million as a long-term liability relating to incentive compensation pursuant to the Manager's LTIP. We currently have \$32 million of available capacity under our credit facilities.

Debt Analysis (\$000s)	As at December 31		
	2007	2006	Change
Long-term debt	178,000	100,000	78%
Short-term debt	—	—	—
Total debt	178,000	100,000	78%
Less: working capital	11,219	9,050	24%
Net debt obligations	166,781	90,950	83%

Because of increased debt related to acquisitions in the third quarter, our ratio of net debt (total debt less positive working capital) to trailing funds generated from operations was 1.4 to 1, at December 31, 2007. In keeping with our conservative approach to debt management, we anticipate that some portion of our cash flow will be directed to debt repayment.

Financial Leverage and Coverage Ratios ⁽¹⁾	As at December 31		
	2007	2006	Change
Net debt to funds generated from operations (times)	1.4	0.8	75%
Net debt to distributions (times)	1.8	0.9	100%
Distributions to interest expense (times)	13.5	19.8	-32%
Net debt to net debt plus equity (%)	40%	21%	90%

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

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 freehold and gross overriding royalty owners are often delayed longer. Therefore, working capital can fluctuate significantly resulting from volume and prices changes relative to each period end.

Components of Working Capital (\$000s)	Dec. 31 2007	Sept. 30 2007	June 30 2007	Mar. 31 2007	Dec. 31 2006
Cash	393	82	254	677	421
Accounts receivable	26,802	26,883	25,865	27,870	29,850
Current assets	27,195	26,965	26,119	28,547	30,271
Distributions payable to Unitholders	(7,398)	(7,392)	(7,387)	(7,381)	(7,376)
Accounts payable and accrued liabilities	(8,578)	(7,891)	(7,491)	(10,124)	(13,845)
Current liabilities	(15,976)	(15,283)	(14,878)	(17,505)	(21,221)
Working capital ⁽¹⁾	11,219	11,682	11,241	11,042	9,050

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

FUTURE INCOME TAX

The implementation of the SIFT legislation 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. Because our property base consisted primarily of royalties, there were few tax pools associated with our assets when the Trust was created in 1996. At year end 2007, we had approximately \$230.9 million available in tax pools. In 2011, with our current tax pools, our distributions will become fully taxable at the entity level under the new rules.

On February 26, 2008, the Minister of Finance delivered the federal government's 2008 budget. Rather than a flat provincial rate of 13% as previously announced, the budget proposes that the provincial component of the SIFT tax will be based on actual provincial corporate tax rates under a formula giving equal weight to province-by-province payrolls and revenues. We have not adjusted our provision for future income tax as legislation to enact the budget proposal has not yet been tabled.

The future income tax liability on our Consolidated Balance Sheet as at December 31, 2007, 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.

TRUST UNITS OUTSTANDING

As at December 31, 2007 and February 27, 2008, there were 49,316,813 Trust Units outstanding. At the end of the fourth quarter, the Trust issued 35,654 Trust Units to the Manager in payment of the quarterly management fee.

As at December 31, 2007 there were 30,473 deferred trust units outstanding and at February 27, 2008 there were 42,722 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement. On January 1, 2008, the Board granted 11,538 deferred trust units to eligible directors of Freehold Resources Ltd. as part of the directors' annual compensation. Each eligible director received 1,923 deferred trust units, and the Chair of the Board received 3,846 deferred trust units.

Trust Units Outstanding	Three Months Ended			Year Ended		
	December 31			December 31		
	2007	2006	Change	2007	2006	Change
Weighted average						
Basic	49,281,547	49,138,931	—	49,228,411	49,085,795	—
Diluted	49,311,402	49,151,287	—	49,228,411	49,093,609	—
At period end	49,316,813	49,174,197	—	49,316,813	49,174,197	—

CRITICAL ACCOUNTING ESTIMATES

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

The Trust has no operational control over its royalty lands, as it primarily holds small royalty interests in several thousand wells. Obtaining timely production data from the well operators is extremely difficult. Thus, we use government reporting databases and past production receipts to estimate revenue accruals.

NEW ACCOUNTING STANDARDS

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

Cash and short-term investments, if any, are held-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 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.

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

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

ENVIRONMENTAL REGULATION AND RISK

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

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

house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

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

On January, 24, 2008, the Alberta Government announced its plan to reduce projected emissions in the province by 50% by the year 2050. This will result in real reductions of 14% below 2005 levels. The Alberta Government stated it will form a government-industry council to determine a go-forward plan for implementing technologies that will significantly reduce greenhouse gas emissions by capturing air emissions from industrial sources and locking them permanently underground in deep rock formations (carbon capture). In addition, the plan calls for energy conservation by individuals, increased investment in clean energy technologies, and incentives for expanding the use of renewable and alternative energy sources such as bioenergy, wind, solar, hydrogen, and geothermal. Initiatives under this theme will account for 18% of Alberta's reductions. A detailed implementation plan is to be developed and released in the spring of 2008.

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

REVIEW OF ALBERTA ROYALTY AND TAX REGIME

On October 25, the Government of Alberta announced its "New Royalty Framework" for Crown oil and gas royalty policy. The new royalty regime, which takes effect January 1, 2009, will be a sliding scale formula based on both commodity prices and well productivity. The government also announced it would review the freehold mineral rights tax to ensure it is fulfilling its intended objective, which is to cover the province's costs of administering the regulatory system.

The royalty rate changes will see the oil and gas industry paying higher Alberta Crown royalties beginning in 2009, which will have a negative impact on producers' future cash flows generated after the new regime takes effect. 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, which is about 900 boe per day or 11% of our total production. Our royalty interest production in Alberta is not affected.

However, the new royalty structure could significantly change the economics of future exploration and development activities in the Province of Alberta. A dramatic reduction in industry drilling would likely be reflected on our royalty lands, but it is not possible to predict what the potential impact might be on Freehold's future production and reserves.

ADDITIONAL INFORMATION

Additional information about Freehold, including our annual information form, is available on SEDAR at www.sedar.com.

Consolidated Balance Sheets

(\$000s) (unaudited)	December 31, 2007	December 31, 2006
Assets		
Current assets:		
Cash	\$ 393	\$ 421
Accounts receivable	26,802	29,850
	<u>27,195</u>	<u>30,271</u>
Reclamation fund	1,788	2,117
Deferred long-term compensation (note 5)	697	86
Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$382,131 (2006 - \$309,731)	474,520	441,754
	<u>\$ 504,200</u>	<u>\$ 474,228</u>
Liabilities and Unitholders' Equity		
Current liabilities:		
Distributions payable to Unitholders	\$ 7,398	\$ 7,376
Accounts payable and accrued liabilities	8,578	13,845
	<u>15,976</u>	<u>21,221</u>
Asset retirement obligation (note 6)	6,608	4,598
Unit based compensation payable (note 5)	1,106	129
Long-term debt (note 3)	178,000	100,000
Future income tax liability (note 8)	51,404	3,832
Unitholders' equity:		
Unitholders' capital (note 4)	564,828	562,698
Contributed surplus (note 5)	512	247
Deficit	(314,234)	(218,497)
	<u>251,106</u>	<u>344,448</u>
	<u>\$ 504,200</u>	<u>\$ 474,228</u>

See accompanying notes to interim consolidated financial statements.

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

(Unaudited) (\$000s, except per unit and weighted average data)	Three Months Ended December 31		Year Ended December 31	
	2007	2006	2007	2006
Revenue:				
Royalty income and working interest sales	\$ 40,511	\$ 32,214	\$ 152,184	\$ 143,067
Royalty expense and freehold mineral tax	(1,293)	(449)	(6,263)	(3,831)
	39,218	31,765	145,921	139,236
Expenses:				
Operating	2,479	2,259	11,076	8,309
General and administrative	1,667	1,100	6,485	5,581
Interest on long-term debt	2,554	1,358	7,005	5,194
Depletion and depreciation	18,601	17,377	72,400	71,874
Accretion of asset retirement obligation	66	65	266	257
Management fee	556	528	2,130	2,649
	25,923	22,687	99,362	93,864
Net income before taxes	13,295	9,078	46,559	45,372
Income and capital taxes	81	(571)	179	291
Future income tax expense (reduction) (note 8)	(5,853)	104	47,572	(100)
	(5,772)	(467)	47,751	191
Net income (loss) and comprehensive income (loss)	\$ 19,067	\$ 9,545	\$ (1,192)	\$ 45,181
Deficit, beginning of period	(305,205)	(204,448)	(218,497)	(160,578)
Distributions declared	(28,096)	(23,594)	(94,545)	(103,100)
Deficit, end of period	\$ (314,234)	\$ (218,497)	\$ (314,234)	\$ (218,497)
Net income (loss) per Trust Unit, basic and diluted	\$ 0.39	\$ 0.19	\$ (0.02)	\$ 0.92
Weighted average number of Trust Units:				
Basic	49,281,547	49,138,931	49,228,411	49,085,795
Diluted	49,311,402	49,151,287	49,228,411	49,093,609

See accompanying notes to interim consolidated financial statements.

Consolidated Statements of Cash Flows

(Unaudited) (\$000s)	Three Months Ended December 31		Year Ended December 31	
	2007	2006	2007	2006
Cash provided by (used in):				
Operating:				
Net income (loss)	\$ 19,067	\$ 9,545	\$ (1,192)	\$ 45,181
Items not involving cash:				
Depletion and depreciation	18,601	17,377	72,400	71,874
Trust Unit incentive compensation (note 5)	242	(124)	631	290
Future income tax expense (reduction) (note 8)	(5,853)	104	47,572	(100)
Accretion of asset retirement obligation	66	65	266	257
Trust Units issued in lieu of management fee	556	528	2,130	2,649
Expenditures on reclamation	(88)	(101)	(799)	(302)
	32,591	27,394	121,008	119,849
Changes in non-cash working capital	(88)	(957)	(1,367)	10,986
	32,503	26,437	119,641	130,835
Financing:				
Long-term debt	(1,000)	2,000	78,000	(7,000)
Distributions paid	(28,091)	(25,061)	(94,524)	(108,471)
	(29,091)	(23,061)	(16,524)	(115,471)
Investing:				
Property and royalty acquisitions	(26)	—	(90,456)	(5,382)
Capital expenditures	(3,901)	(3,766)	(12,167)	(11,446)
Change in reclamation fund	(31)	(15)	329	(153)
Changes in non-cash working capital	857	241	(851)	1,846
	(3,101)	(3,540)	(103,145)	(15,135)
Increase (decrease) in cash	311	(164)	(28)	229
Cash, beginning of period	82	585	421	192
Cash, end of period	\$ 393	\$ 421	\$ 393	\$ 421

See accompanying notes to interim consolidated financial statements.

Notes to Interim Consolidated Financial Statements

For the period ended December 31, 2007.

1. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Freehold Royalty Trust (Freehold or the Trust) have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2006, except for the new standards regarding financial instruments detailed below. The following disclosure is incremental to the disclosure contained in the notes to the 2006 annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes for the year ended December 31, 2006.

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

NEW ACCOUNTING STANDARDS

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

Cash and short-term investments, if any, are held-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 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.

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

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

2. PROPERTY ACQUISITIONS

On August 31, 2007, Freehold closed an acquisition of certain overriding royalty interests in Alberta and Saskatchewan for \$57.6 million, net of adjustments. The acquisition was effective March 1, 2007, with results of operations being included from September 1, 2007. On September 5, 2007, Freehold closed an acquisition of a gross overriding royalty interest on a property in Alberta for \$32.8 million, net of adjustments. The acquisition was effective August 1, 2007, with results of operations being included from September 5, 2007. Both acquisitions were funded through Freehold's credit facilities.

3. LONG-TERM DEBT

Freehold has a \$195 million extendible revolving term credit facility, extendible annually, on which \$178 million was drawn at December 31, 2007. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a two-year, non-revolving term facility with equal quarterly principal repayments. The first quarterly payment would commence on January 1 of the year following the end of the revolving period, which is May 2008. In addition, Freehold has available a \$15 million extendible revolving operating facility.

Borrowings under the facilities bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 85 to 140 basis points and standby fees.

The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets.

4. UNITHOLDERS' CAPITAL

	December 31, 2007		December 31, 2006	
	Units	Amount (\$000s)	Units	Amount (\$000s)
Balance, beginning of period	49,174,197	562,698	49,031,581	560,049
Issued in lieu of management fee	142,616	2,130	142,616	2,649
Balance, end of period	49,316,813	564,828	49,174,197	562,698

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.

5. UNIT BASED COMPENSATION

(a) Deferred Trust Unit Plan

Fully-vested deferred trust units are granted annually to non-management directors. Distributions to Unitholders declared by the Trust prior to redemption are assumed to be reinvested in notional units of the date of distribution. As at December 31, 2007, there were 30,473 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement.

Deferred Trust Units	December 31, 2007	December 31, 2006
Balance, beginning of period	12,559	—
Annual grant	14,181	11,165
Additional units resulting from distributions	3,733	1,394
Balance, end of period	30,473	12,559

For the three months ended December 31, 2007, Freehold expensed \$17,000 (2006 – \$6,000) as unit based compensation with a corresponding increase to contributed surplus. The total for the year ended December 31, 2007 was \$265,000 (2006 – \$247,000).

Contributed Surplus (\$000s)	December 31, 2007	December 31, 2006
Balance, beginning of period	247	—
Trust Unit incentive compensation expense	265	247
Balance, end of period	512	247

(b) Manager's Long-Term Incentive Plan

Employees of the Manager receive cash compensation in relation to the value of a specified number of notional units after a three year vesting period. Distributions to Unitholders declared by the Trust during the vesting period are assumed to be reinvested in notional units on the date of distribution. For the three months ended December 31, 2007, Freehold expensed \$225,000 (2006 – recovered \$130,000) as unit based compensation. The total for the year ended December 31, 2007 was \$366,000 (2006 – \$43,000). At December 31, 2007, Freehold had recorded \$697,000 as a deferred long-term compensation asset and accrued \$1,106,000 as a long-term liability.

6. ASSET RETIREMENT OBLIGATIONS

Freehold has no asset retirement obligations on its royalty income properties. Freehold's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of Freehold's total asset retirement obligation is estimated to be \$6.6 million (discounted at a weighted average, credit adjusted, risk free rate of 5.8%), the undiscounted value of which is \$23.6 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being over 15 years away.

Asset Retirement Obligations (\$000s)	December 31, 2007	December 31, 2006
Balance, beginning of period	4,598	4,036
Liabilities incurred	675	364
Liabilities settled	(799)	(302)
Revisions in estimates	1,868	243
Accretion expense	266	257
Balance, end of period	6,608	4,598

7. RELATED PARTY TRANSACTIONS

For the three months ended December 31, 2007, Freehold issued 35,654 Trust Units as management fee to the Manager (2006 – 35,654 Trust Units) pursuant to a management agreement. The total for the year ended December 31, 2007 was 142,616 Trust Units (2006 – 142,616 Trust Units).

For the three months ended December 31, 2007, the Manager charged the Trust \$0.9 million in general and administrative costs (2006 – \$0.8 million). The total for the year ended December 31, 2007 was \$4.4 million (2006 – \$3.7 million). At December 31, 2007, there was \$0.3 million in accounts payable and accrued liabilities 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.

8. FUTURE INCOME TAXES

On June 22, 2007, *Bill C-52 Budget Implementation Act, 2007*, which contained legislation to tax certain publicly-traded, specified income flow-through (SIFT) entities in Canada, received Royal Assent and became law. As a result, we recorded \$54.3 million of future income tax expense with a corresponding increase in future income tax liability in the second quarter of 2007. In December 2007, the federal government substantively enacted tax rate reductions, which lowered the corporate tax rates for 2008 to 20.5% with further yearly reductions to an ultimate rate of 15% in 2012 and future years. These rate reductions also lower the trust taxation rate (as enacted by the federal government in the second quarter of 2007 for years commencing in 2011) from 31.5% to 29.5% in 2011 and to 28% in 2012 and future years. Accordingly, we recorded a \$5.9 million future income tax recovery in the fourth quarter of 2007.

The future income tax liability on our Consolidated Balance Sheet as at December 31, 2007, 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.

9. SUPPLEMENTAL CASH FLOW DISCLOSURE

Cash Expenses Paid (\$000s)	Three Months Ended		Year Ended	
	December 31		December 31	
	2007	2006	2007	2006
Interest	2,517	1,323	7,256	5,294
Taxes	(199)	276	(690)	1,251

Corporate Information

BOARD OF DIRECTORS

William W. Siebens⁽²⁾
President and Chief Executive Officer
Candor Investments Ltd.

D. Nolan Blades⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾
President
Sunny Gables Holdings Ltd.

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

Tullio Cedraschi
Corporate Director

Peter T. Harrison⁽¹⁾⁽³⁾⁽⁴⁾
Senior Vice-President
Monrusco Bolton Investments Inc.

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

David J. Sandmeyer
President & Chief Executive Officer
Rife Resources Ltd.

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

2007 FOURTH QUARTER DISTRIBUTIONS DECLARED

Record Date	Payment Date	Per Trust Unit
October 31, 2007	November 15, 2007	\$0.15
November 30, 2007	December 15, 2007	\$0.27 ⁽¹⁾
December 31, 2007	January 15, 2008	<u>\$0.15</u>
		<u>\$0.57</u>

(1) includes \$0.12 additional distribution

TAX INFORMATION AND HISTORICAL DISTRIBUTIONS

Tax information and historical distributions are available on our website at www.freeholdtrust.com.

OFFICERS

William W. Siebens
Chair of the Board

David J. Sandmeyer
President and Chief Executive Officer

J. Frank George
Vice-President, Exploitation

Darren G. Gunderson
Controller

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

William O. Ingram
Vice-President, Production

Michael J. Okrusko
Vice-President, Land

Karen C. Taylor
Corporate Secretary

HEAD OFFICE

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

INVESTOR RELATIONS CONTACT

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

WEBSITE

www.freeholdtrust.com

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading Symbol: FRU.UN

2007 FOURTH QUARTER

TRADING SUMMARY

High – \$15.85
Low – \$14.46
Close – \$15.60
Volume – 7,035,824
Trust Units Outstanding – 49.3 million
Market Capitalization – \$769 million
(December 31)

TRUSTEE AND TRANSFER AGENT

Computershare Trust Company of Canada
600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Toll Free: 1-888-267-6555
Fax: (403) 267-6598
Email: service@computershare.com

LEGAL COUNSEL

Burnet Duckworth & Palmer, LLP
Calgary, Alberta

AUDITORS

KPMG, LLP
Calgary, Alberta

BANKERS

Canadian Imperial Bank of Commerce
Calgary, Alberta

Royal Bank of Canada
Calgary, Alberta

RESERVE EVALUATORS

Trimble Engineering Associates Ltd.
Calgary, Alberta