



## Quarterly Report

THREE AND TWELVE MONTHS ENDED DECEMBER 31, 2008

# Freehold Royalty Trust Announces 2008 Fourth Quarter and Annual Results and Year-End Reserves

### RESULTS AT A GLANCE

| Financial (\$000s, except as noted)     | Three Months Ended<br>December 31 |         |        | Twelve Months Ended<br>December 31 |         |        |
|-----------------------------------------|-----------------------------------|---------|--------|------------------------------------|---------|--------|
|                                         | 2008                              | 2007    | Change | 2008                               | 2007    | Change |
| Gross revenue                           | 34,461                            | 40,511  | -15%   | 204,116                            | 152,184 | 34%    |
| Net income (loss)                       | 13,374                            | 19,067  | -30%   | 109,956                            | (1,192) | -      |
| Per Trust Unit, basic and diluted (\$)  | 0.27                              | 0.39    | -30%   | 2.23                               | (0.02)  | -      |
| Cash provided by operating activities   | 41,672                            | 32,503  | 28%    | 179,252                            | 119,641 | 50%    |
| Per Trust Unit (\$)                     | 0.84                              | 0.66    | 27%    | 3.63                               | 2.43    | 49%    |
| Funds generated from operations (1)     | 26,942                            | 32,591  | -17%   | 171,282                            | 121,008 | 42%    |
| Per Trust Unit (\$)                     | 0.55                              | 0.66    | -17%   | 3.47                               | 2.46    | 41%    |
| Capital expenditures                    | 3,770                             | 3,901   | -3%    | 12,992                             | 12,167  | 7%     |
| Property and royalty acquisitions (net) | (782)                             | 26      | -      | 7,693                              | 90,456  | -91%   |
| Distributions declared                  | 54,387                            | 28,096  | 94%    | 143,749                            | 94,545  | 52%    |
| Per Trust Unit (\$) (2)                 | 1.10                              | 0.57    | 93%    | 2.91                               | 1.92    | 52%    |
| Long-term debt, period end              | 140,000                           | 178,000 | -21%   | 140,000                            | 178,000 | -21%   |
| Unitholders' equity, period end         | 220,005                           | 251,106 | -12%   | 220,005                            | 251,106 | -12%   |
| Trust Units (000s) (3)                  | 49,424                            | 49,282  | 0%     | 49,371                             | 49,228  | 0%     |
| <b>Operating (per boe) (4)</b>          |                                   |         |        |                                    |         |        |
| Average daily production (boe/d)        | 7,779                             | 8,591   | -9%    | 7,804                              | 8,484   | -8%    |
| Average price realizations (\$)         | 46.55                             | 50.57   | -8%    | 69.93                              | 48.63   | 44%    |
| Operating netback (\$) (1)              | 42.14                             | 46.47   | -9%    | 65.18                              | 43.54   | 50%    |

(1) See non-GAAP measures.

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

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

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

As a result of higher average commodity prices during 2008, cash provided by operating activities increased 50% and funds generated from operations increased 42% for the year. Distributions reached a record \$2.91 per Trust Unit, more than 50% higher than in 2007. From inception to December 31, 2008, the Trust has distributed \$724 million (\$19.13 per Trust Unit) to Unitholders.

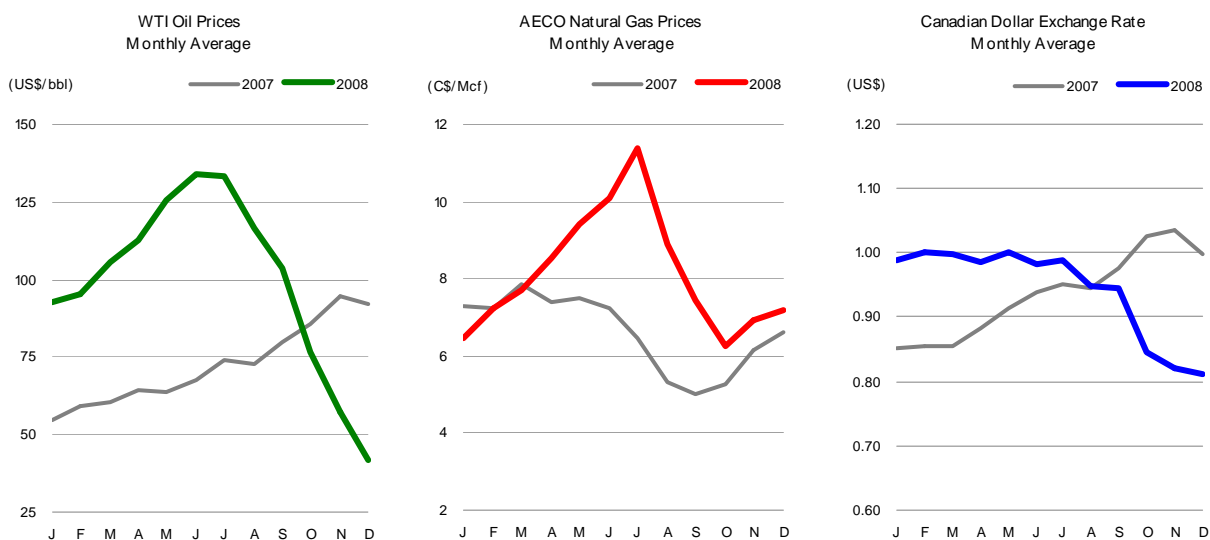
With the significant decline in commodity prices in the last quarter of 2008, the Board of Directors has declared the March distribution of \$0.10 per Trust Unit, which will be paid on April 15, 2009 to Unitholders of record on March 31, 2009 (ex-distribution date March 27, 2009). Including the April 15, 2009 payment, our 12-month trailing cash distributions total \$2.76 per Trust Unit.

## Message to Unitholders

Results for the twelve months ended December 31, 2008 reflect higher average commodity prices for the year, while results for the fourth quarter reflect the steep decline in commodity prices in the final months of 2008. 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. Commodity price and currency rate fluctuations serve to reinforce that our cash flows, and thus our distributions, are largely dependant on cyclical supply and demand factors that are beyond our control. Notwithstanding our exposure to this price volatility, we continue to believe our 'no hedging' policy is the right strategy for Freehold.

The following summary is aimed at helping investors better understand the impact of price volatility on our results, and therefore on our distributions.

- WTI crude prices have exhibited significant volatility in the last two years. 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 gain was somewhat muted by the rising value of the Canadian dollar relative to its U.S. counterpart.
- WTI prices declined modestly through the third quarter of 2008 and then plunged rapidly in the fourth quarter, causing revenues to decline sharply as well. This steep price decline resulted from a drop in demand for crude oil due to the rapidly deteriorating global economic picture. The Canadian dollar, which had been trading on parity with the U.S. dollar, also weakened by 20%.
- AECO natural gas prices have also exhibited significant volatility, dipping as low as Cdn\$5.02 per thousand cubic feet (Mcf) in September 2007. Natural gas markets began to strengthen in the first quarter of 2008, and we benefited from higher prices in the first nine months of 2008. However, natural gas prices also faced sharp downward pressure through the fourth quarter due to weak North American supply and demand fundamentals.
- We have adjusted our monthly distributions in response to changing commodity prices. In January 2007 (when WTI oil prices averaged US\$58.65 per barrel), our distribution 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. 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 and declared an additional distribution of \$0.35 per Trust Unit for 2008. In January 2009, with weakening demand pushing commodity prices lower, we lowered the monthly distribution to \$0.10 per Trust Unit to preserve operating stability and financial flexibility.



## OPERATIONAL UPDATE

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 distributed \$19.13 per Trust Unit, almost double the IPO price of \$10.00.

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

Our 2008 capital and acquisition program was successful in replacing 45% of our production for the year. We spent \$13 million on development activities, adding 0.8 million boe of net proved plus probable reserves at an average cost of \$14.92 per boe. In addition, we spent \$7.7 million on royalty acquisitions, acquiring 0.3 million 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.

We’re particularly pleased with the success we’ve had to date on undeveloped mineral title lands 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 Basin, there is potential to employ this strategy in other areas in the future.

Based on the independent evaluation of our reserves as at December 31, 2008, the present value of our net proved plus probable oil and gas reserves (discounted at 10%, before tax), was \$730.7 million, up from \$711.6 million at the end of 2007. Our undeveloped land was independently valued at \$94 million. This represents a 310% increase over the prior year, mainly due to a higher value attributed to our mineral title lands in Southeast Saskatchewan. Higher land and reserves values contributed to an 18% increase in net asset value per Trust Unit.

Excluding any potential acquisitions, 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.

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 reduction 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 royalty 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.

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. Tightening credit markets and a deepening global recession have created turmoil in financial and equity markets, causing significant reductions 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. While these issues may affect our ability to access financing for potential future acquisitions, we are not reliant on debt or equity markets to finance operating activities. In the near term, with the expectation that commodity prices will remain weak, our Board has established a distribution policy for the second quarter of 2009 of \$0.10 per Trust Unit per month based on the key operating assumptions outlined in our fourth quarter MD&A. We will review this policy monthly and make adjustments, if necessary, to ensure that cash distributions are in line with expected cash flow.

#### **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, 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. We anticipate the committee's recommendation by the end of 2009. 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 other oil and gas trusts.

#### **BOARD AND MANAGEMENT CHANGES**

Bill Siebens, Chair of the Board of Freehold Resources since 1996, plans to retire from the Board in 2009 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 broad perspective he has added to the Board's strategic decision making. Joe Holowisky, who retired in January, has been a vital member of our management team for more than 27 years. As Freehold's Chief Financial Officer since 1996, his contributions have been significant. Although Joe's shoes will be difficult to fill, we are fortunate that Darren Gunderson has been able to step into the CFO position without missing a beat.

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, currently Executive Vice-President and Chief Operating Officer of Freehold, as my successor. At the pleasure of our Unitholders, I hope to remain on the Board. However, 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.

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



David J. Sandmeyer  
President and Chief Executive Officer

## Summary of Reserves

Our oil and natural gas reserves were independently evaluated by Trimble Engineering Associates Ltd. (Trimble) as at December 31, 2008. The evaluation was conducted in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in National Instrument 51-101 (NI 51-101).

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

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

As at December 31, 2008, reserves were assigned to 23,916 wells. On a boe basis, our reserves profile is 38% natural gas, 34% heavy oil, 23% light and medium oil, and 5% natural gas liquids (NGL). Approximately 65% of our reserves are in the proved category, and 99% of our proved reserves are producing, which is high by industry standards

| OIL AND GAS RESERVES<br>AS AT DECEMBER 31, 2008 <sup>(1)</sup> | Light and Medium<br>Crude Oil |                    | Heavy Crude Oil      |                    | Total Crude Oil      |                    |
|----------------------------------------------------------------|-------------------------------|--------------------|----------------------|--------------------|----------------------|--------------------|
|                                                                | Gross <sup>(2)</sup>          | Net <sup>(3)</sup> | Gross <sup>(2)</sup> | Net <sup>(3)</sup> | Gross <sup>(2)</sup> | Net <sup>(3)</sup> |
|                                                                | (Mbbbl)                       | (Mbbbl)            | (Mbbbl)              | (Mbbbl)            | (Mbbbl)              | (Mbbbl)            |
| Reserves Category                                              |                               |                    |                      |                    |                      |                    |
| Proved developed producing                                     | 1,706                         | 3,839              | 1,151                | 5,311              | 2,858                | 9,150              |
| Proved developed non-producing                                 | 60                            | 52                 | 20                   | 113                | 79                   | 165                |
| Proved undeveloped                                             | -                             | -                  | -                    | -                  | -                    | -                  |
| <b>Total proved</b>                                            | <b>1,766</b>                  | <b>3,891</b>       | <b>1,171</b>         | <b>5,424</b>       | <b>2,937</b>         | <b>9,315</b>       |
| Probable                                                       | 804                           | 1,971              | 578                  | 3,160              | 1,382                | 5,131              |
| <b>Total proved plus probable</b>                              | <b>2,570</b>                  | <b>5,862</b>       | <b>1,749</b>         | <b>8,584</b>       | <b>4,319</b>         | <b>14,446</b>      |

| Reserves Category                 | Natural Gas          |                    | Natural Gas Liquids  |                    | Oil Equivalent <sup>(4)</sup> |                    |
|-----------------------------------|----------------------|--------------------|----------------------|--------------------|-------------------------------|--------------------|
|                                   | Gross <sup>(2)</sup> | Net <sup>(3)</sup> | Gross <sup>(2)</sup> | Net <sup>(3)</sup> | Gross <sup>(2)</sup>          | Net <sup>(3)</sup> |
|                                   | (Mbbbl)              | (Mbbbl)            | (MMcft)              | (MMcft)            | (Mboe)                        | (Mboe)             |
| Proved developed producing        | 5,316                | 38,132             | 198                  | 815                | 3,941                         | 16,321             |
| Proved developed non-producing    | 19                   | 121                | 1                    | -                  | 83                            | 185                |
| Proved undeveloped                | -                    | -                  | -                    | -                  | -                             | -                  |
| <b>Total proved</b>               | <b>5,335</b>         | <b>38,253</b>      | <b>198</b>           | <b>816</b>         | <b>4,024</b>                  | <b>16,506</b>      |
| Probable                          | 2,775                | 20,095             | 90                   | 387                | 1,935                         | 8,867              |
| <b>Total proved plus probable</b> | <b>8,110</b>         | <b>58,348</b>      | <b>289</b>           | <b>1,203</b>       | <b>5,959</b>                  | <b>25,374</b>      |

(1) Numbers may not add due to rounding.

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

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

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

| RECONCILIATION OF NET<br>OIL AND GAS RESERVES<br>BY PRINCIPAL PRODUCT TYPE <sup>(1) (2)</sup> | Light and                       | Heavy                 | Total                 | Natural                 | Associated    | Oil                                 |
|-----------------------------------------------------------------------------------------------|---------------------------------|-----------------------|-----------------------|-------------------------|---------------|-------------------------------------|
|                                                                                               | Medium<br>Crude Oil<br>(Mbbbls) | Crude Oil<br>(Mbbbls) | Crude Oil<br>(Mbbbls) | Gas Liquids<br>(Mbbbls) | Gas<br>(MMcf) | Equivalent <sup>(4)</sup><br>(Mboe) |
| <b>Proved Producing</b>                                                                       |                                 |                       |                       |                         |               |                                     |
| December 31, 2007                                                                             | 4,230                           | 6,238                 | 10,468                | 937                     | 40,438        | 18,144                              |
| Extensions                                                                                    | 146                             | 155                   | 301                   | 12                      | 581           | 409                                 |
| Improved recovery                                                                             | -                               | -                     | -                     | -                       | -             | -                                   |
| Technical revisions                                                                           | 146                             | (104)                 | 42                    | 5                       | 2,780         | 511                                 |
| Discoveries                                                                                   | -                               | -                     | -                     | -                       | -             | -                                   |
| Acquisitions                                                                                  | 57                              | 32                    | 89                    | -                       | 618           | 192                                 |
| Dispositions                                                                                  | -                               | -                     | -                     | -                       | -             | -                                   |
| Economic factors                                                                              | (125)                           | (7)                   | (132)                 | 8                       | 400           | (58)                                |
| Production <sup>(3)</sup>                                                                     | (614)                           | (1,003)               | (1,617)               | (147)                   | (6,684)       | (2,877)                             |
| <b>December 31, 2008</b>                                                                      | <b>3,839</b>                    | <b>5,311</b>          | <b>9,150</b>          | <b>815</b>              | <b>38,132</b> | <b>16,321</b>                       |
| <b>Total Proved</b>                                                                           |                                 |                       |                       |                         |               |                                     |
| December 31, 2007                                                                             | 4,230                           | 6,373                 | 10,602                | 939                     | 40,662        | 18,318                              |
| Extensions                                                                                    | 146                             | 155                   | 301                   | 12                      | 581           | 409                                 |
| Improved recovery                                                                             | -                               | -                     | -                     | -                       | -             | -                                   |
| Technical revisions                                                                           | 197                             | (128)                 | 69                    | 4                       | 2,674         | 519                                 |
| Discoveries                                                                                   | -                               | -                     | -                     | -                       | -             | -                                   |
| Acquisitions                                                                                  | 57                              | 32                    | 89                    | -                       | 618           | 192                                 |
| Dispositions                                                                                  | -                               | -                     | -                     | -                       | -             | -                                   |
| Economic factors                                                                              | (125)                           | (5)                   | (130)                 | 8                       | 402           | (55)                                |
| Production <sup>(3)</sup>                                                                     | (614)                           | (1,003)               | (1,617)               | (147)                   | (6,684)       | (2,877)                             |
| <b>December 31, 2008</b>                                                                      | <b>3,891</b>                    | <b>5,424</b>          | <b>9,315</b>          | <b>816</b>              | <b>38,253</b> | <b>16,506</b>                       |
| <b>Proved Plus Probable</b>                                                                   |                                 |                       |                       |                         |               |                                     |
| December 31, 2007                                                                             | 6,128                           | 10,210                | 16,338                | 1,394                   | 61,381        | 27,963                              |
| Extensions                                                                                    | 235                             | 330                   | 565                   | 18                      | 1,503         | 833                                 |
| Improved recovery                                                                             | -                               | -                     | -                     | -                       | -             | -                                   |
| Technical revisions                                                                           | 221                             | (985)                 | (764)                 | (73)                    | 786           | (706)                               |
| Discoveries                                                                                   | -                               | -                     | -                     | -                       | -             | -                                   |
| Acquisitions                                                                                  | 82                              | 44                    | 126                   | -                       | 876           | 272                                 |
| Dispositions                                                                                  | -                               | -                     | -                     | -                       | -             | -                                   |
| Economic factors                                                                              | (191)                           | (13)                  | (204)                 | 11                      | 485           | (112)                               |
| Production <sup>(3)</sup>                                                                     | (614)                           | (1,003)               | (1,617)               | (147)                   | (6,684)       | (2,877)                             |
| <b>December 31, 2008</b>                                                                      | <b>5,862</b>                    | <b>8,584</b>          | <b>14,446</b>         | <b>1,203</b>            | <b>58,348</b> | <b>25,374</b>                       |

(1) Numbers may not add due to rounding.

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

(3) Production estimated by Trimble.

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

| RESERVE LIFE INDEX <sup>(1)</sup> | Proved<br>Producing | Total<br>Proved | Proved Plus<br>Probable |
|-----------------------------------|---------------------|-----------------|-------------------------|
| Net reserves (Mboe)               | 16,321              | 16,506          | 25,374                  |
| Net production (Mboe)             | 2,355               | 2,371           | 2,601                   |
| Reserve life index (years)        | 6.9                 | 7.0             | 9.8                     |

(1) Calculated by dividing the Trimble forecast of 2009 net production into the remaining net reserves.

#### TOTAL FUTURE NET REVENUE (UNDISCOUNTED)

AS AT DECEMBER 31, 2008 - FORECAST PRICES AND COSTS <sup>(1) (2)</sup>

| (\$000s)                                       | Proved    | Proved Plus<br>Probable |
|------------------------------------------------|-----------|-------------------------|
| Royalty Income                                 | 879,039   | 1,525,343               |
| Revenue from Working Interest Properties       | 349,781   | 563,005                 |
| Royalty expense on Working Interest Properties | (44,365)  | (76,961)                |
| Operating costs                                | (128,094) | (199,838)               |
| Development costs                              | (1,172)   | (3,706)                 |
| Well abandonment and reclamation costs         | (7,874)   | (9,152)                 |
| Future net revenue before income taxes         | 1,047,314 | 1,798,692               |
| Future income taxes                            | (175,762) | (360,218)               |
| Future net revenue after income taxes          | 871,552   | 1,438,474               |

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

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

#### FUTURE DEVELOPMENT COSTS <sup>(1)</sup>

| (\$000s)  | Proved Reserves | Proved Plus<br>Probable Reserves |
|-----------|-----------------|----------------------------------|
| 2009      | 70              | 1,074                            |
| 2010      | 78              | 1,082                            |
| 2011      | 73              | 1,099                            |
| 2012      | 74              | 74                               |
| 2013      | 30              | 30                               |
| Remainder | 848             | 347                              |
| Total     | 1,173           | 3,706                            |

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

#### NET PRESENT VALUES

OF FUTURE NET REVENUE <sup>(1) (2) (3)</sup>

| (\$000s)                       | Before tax, discounted at |             |              |              |
|--------------------------------|---------------------------|-------------|--------------|--------------|
|                                | 0% per year               | 5% per year | 10% per year | 15% per year |
| Proved developed producing     | 1,037,477                 | 698,659     | 531,442      | 432,955      |
| Proved developed non-producing | 9,837                     | 7,395       | 5,895        | 4,894        |
| Proved undeveloped             | -                         | -           | -            | -            |
| Total proved                   | 1,047,314                 | 706,054     | 537,337      | 437,849      |
| Total probable                 | 751,378                   | 328,262     | 193,322      | 133,697      |
| Proved plus probable           | 1,798,692                 | 1,034,316   | 730,659      | 571,546      |

(1) Columns may not add due to rounding.

(2) Forecast prices and costs, before tax. Based on the December 31, 2008 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

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

| <b>ANALYSIS OF DEVELOPMENT AND ACQUISITIONS COSTS</b> (1) (2) (3) (4) | 2008         | 2007         | 2006         | Three-Year Results |
|-----------------------------------------------------------------------|--------------|--------------|--------------|--------------------|
| <b>Net Proved Reserves:</b>                                           |              |              |              |                    |
| Development expenditures (\$000s)                                     | 12,992       | 12,167       | 11,446       | 36,605             |
| Change in future development capital estimates (\$000s)               | 597          | (2,376)      | 260          | (1,519)            |
| Net reserve additions by development (Mboe)                           | 409          | 329          | 651          | 1,389              |
| <b>Development costs (\$/boe)</b>                                     | <b>33.22</b> | <b>29.79</b> | <b>17.98</b> | <b>25.26</b>       |
| Acquisition expenditures (\$000s)                                     | 7,693        | 90,456       | 5,382        | 103,531            |
| Net reserve additions by acquisition (Mboe)                           | 192          | 1,696        | 256          | 2,144              |
| <b>Acquisition costs (\$/boe)</b>                                     | <b>40.07</b> | <b>53.33</b> | <b>21.00</b> | <b>48.29</b>       |
| Total expenditures (\$000s)                                           | 20,685       | 102,623      | 16,828       | 140,136            |
| Change in future development capital estimates (\$000s)               | 597          | (2,376)      | 260          | (1,519)            |
| Net reserve additions (Mboe)                                          | 601          | 2,025        | 907          | 3,533              |
| <b>Development and acquisition costs (\$/boe)</b>                     | <b>35.41</b> | <b>49.50</b> | <b>18.84</b> | <b>39.23</b>       |
| <b>Net Proved Plus Probable Reserves:</b>                             |              |              |              |                    |
| Development expenditures (\$000s)                                     | 12,992       | 12,167       | 11,446       | 36,605             |
| Change in future development capital estimates (\$000s)               | (564)        | (3,305)      | (2,549)      | (6,418)            |
| Net reserve additions by development (Mboe)                           | 833          | 616          | 1,146        | 2,595              |
| <b>Development costs (\$/boe)</b>                                     | <b>14.92</b> | <b>14.38</b> | <b>7.76</b>  | <b>11.63</b>       |
| Acquisition expenditures (\$000s)                                     | 7,693        | 90,456       | 5,382        | 103,531            |
| Net reserve additions by acquisition (Mboe)                           | 272          | 2,473        | 376          | 3,121              |
| <b>Acquisition costs (\$/boe)</b>                                     | <b>28.25</b> | <b>36.57</b> | <b>14.33</b> | <b>33.17</b>       |
| Total expenditures (\$000s)                                           | 20,685       | 102,623      | 16,828       | 140,136            |
| Change in future development capital estimates (\$000s)               | (564)        | (3,305)      | (2,549)      | (6,418)            |
| Net reserve additions (Mboe)                                          | 1,105        | 3,090        | 1,522        | 5,717              |
| <b>Development and acquisition costs (\$/boe)</b>                     | <b>18.20</b> | <b>32.15</b> | <b>9.38</b>  | <b>23.39</b>       |

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

## RECYCLE STATISTICS

| <b>NET PROVED PLUS PROBABLE RESERVES</b><br>(\$ per boe, except as noted) (1) | 2008  | 2007  | 2006  | Three-Year Results |
|-------------------------------------------------------------------------------|-------|-------|-------|--------------------|
| Operating netback (2) (5)                                                     | 65.18 | 43.54 | 42.64 | 50.09              |
| Development and acquisition costs (3) (5)                                     | 18.20 | 32.15 | 9.38  | 23.39              |
| Recycle ratio (times) (4)                                                     | 3.6   | 1.4   | 4.5   | 2.1                |

- (1) See "Management's Discussion and Analysis (MD&A) - Conversion of Natural Gas to Barrels of Oil Equivalent (boe)".
- (2) Total revenue, less operating costs and royalty expenses (net of Alberta Royalty Credit in 2006).
- (3) Development expenditures, plus change in future capital, plus acquisition costs; divided by net reserves added through development and acquisition activities.
- (4) Operating netback divided by the average cost of acquiring and developing new reserves.
- (5) Operating netback is based on gross production, while development and acquisition costs are based on net reserves.

## Summary of Land Holdings

At December 31, 2008, our land holdings encompassed approximately 2.4 million gross acres, unchanged from 2007. Approximately 91% of our total land holdings are royalty interests.

| SUMMARY OF LAND HOLDINGS<br>(gross acres) (1) | Total Land Holdings |           | Undeveloped Land |         |
|-----------------------------------------------|---------------------|-----------|------------------|---------|
|                                               | 2008                | 2007      | 2008             | 2007    |
| Mineral title lands (2)                       | 549,925             | 549,758   | 162,972          | 160,034 |
| Gross overriding royalty (GORR) lands (3)     | 1,518,423           | 1,526,878 | 423,188          | 360,832 |
| Royalty assumption lands (4)                  | 95,592              | 96,072    | 19,962           | 19,648  |
| Total royalty lands                           | 2,163,940           | 2,172,708 | 606,122          | 540,514 |
| Working interest properties                   | 210,606             | 207,428   | 44,998           | 48,585  |
| Total land holdings                           | 2,374,546           | 2,380,136 | 651,120          | 589,099 |

- (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.

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<br>(gross acres) (1) | As at December 31 |           |           |
|------------------------------------------------|-------------------|-----------|-----------|
|                                                | 2008              | 2007      | 2006      |
| Alberta                                        | 1,485,388         | 1,488,098 | 1,218,097 |
| Saskatchewan                                   | 503,634           | 505,223   | 464,977   |
| Ontario                                        | 295,769           | 296,109   | 296,109   |
| British Columbia                               | 81,472            | 82,423    | 81,904    |
| Manitoba                                       | 8,283             | 8,283     | 8,283     |
| Total                                          | 2,374,546         | 2,380,136 | 2,069,370 |

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

## Net Asset Value<sup>(1)</sup>

Our net asset value at December 31, 2008 was \$13.92 per Trust Unit, up 17% from year-end 2007. The present value of our net proved plus probable oil and gas reserves, discounted at 10%, before tax, increased slightly to \$730.7 million because of higher forecast prices used by our independent engineers in the 2008 evaluation. Similarly, higher forecast prices account for the majority of the increase in the value of our potash reserves. The value of our undeveloped land rose significantly in 2008; the largest increase was in Southeast Saskatchewan. The independent land evaluation took into account land sale activity during 2008. Crown land sales were robust for most of the year, particularly in the Bakken trend in Southeast Saskatchewan where we hold 10,000 gross acres of mineral title lands.

### NET ASSET VALUE AS AT DECEMBER 31, 2008<sup>(1) (2) (7)</sup>

| (\$000s, except unit data)                               | 2008         | 2007         | 2006         |
|----------------------------------------------------------|--------------|--------------|--------------|
| Present value of oil and gas reserves <sup>(3) (8)</sup> | 730,659      | 711,624      | 636,267      |
| Present value of potash reserves <sup>(4) (8)</sup>      | 27,807       | 14,317       | 10,530       |
| Undeveloped land <sup>(5)</sup>                          | 93,975       | 30,252       | 19,412       |
| Reclamation fund <sup>(6)</sup>                          | 1,827        | 1,788        | 2,117        |
| Working capital <sup>(6)</sup>                           | (20,055)     | 11,219       | 9,050        |
| Bank debt <sup>(6)</sup>                                 | (140,000)    | (178,000)    | (100,000)    |
| Asset retirement obligations <sup>(6)</sup>              | (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       |
| <b>Net asset value per Trust Unit (\$)</b>               | <b>13.92</b> | <b>11.85</b> | <b>11.65</b> |

- (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 restated to conform to current presentation.
- (8) Future net revenue values do not represent fair market value.

## Management's Discussion and Analysis (MD&A)

The following discussion is management's opinion about the operating and financial results of Freehold Royalty Trust, Freehold Resources Ltd. and Petrovera Resources (a general partnership) (collectively, Freehold or the Trust), for the three months 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 quarters ended December 31, 2008 and December 31, 2007, 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, 2007 and 2006, together with the accompanying notes.

Additional information about Freehold, including our annual information form (AIF), is available on SEDAR at [www.sedar.com](http://www.sedar.com) and on our website at [www.freeholdtrust.com](http://www.freeholdtrust.com).

### FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of Freehold's future plans and operations as at March 11, 2009, and contains forward-looking statements including our expectations for production, capital and distributions referred to in the Message to Unitholders; our expected sources of funds for distributions and capital expenditures referred to under Liquidity and Capital Resources – Capital Expenditures; Future Income Tax; and our drilling plans, production guidance, distribution policy and our key operating assumptions referred to under the Outlook. These forward-looking statements are provided to allow readers to better understand our business and prospects.

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

With respect to forward-looking statements contained in this MD&A, we have made assumptions regarding, among other things, future oil and natural gas prices; future capital expenditure levels; future production levels; future exchange rates; 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 expectation for consumption of crude oil and natural gas; our expectation for industry drilling levels; our ability to obtain financing on acceptable terms; our expectations with respect to maintaining our current structure and timing of a recommendation of the Corporate SIFT Tax Strategy Committee; 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 referred to above.

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

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

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

## NON-GAAP MEASURES

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

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

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

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

## Development Activities

### INDUSTRY ACTIVITY

According to statistics published by the Canadian Association of Oilwell Drilling Contractors, a total of 7,913 wells were drilled in western Canada during the fourth quarter of 2008, a 50% increase from the fourth quarter last year. For the full year 2008, industry drilling was 8% higher than 2007.

### ROYALTY INTEREST LANDS

Drilling on our royalty lands generally mirrors industry drilling, with slight timing differences. On an equivalent net basis, royalty drilling was up 3% in the fourth quarter and down 5% for the year. As at December 31, 2008, there were 64 (2007 – 92) licensed drilling locations on our royalty lands.

| DRILLING ON ROYALTY LANDS | Three Months Ended |      |        | Twelve Months Ended |      |        |
|---------------------------|--------------------|------|--------|---------------------|------|--------|
|                           | December 31        |      |        | December 31         |      |        |
|                           | 2008               | 2007 | Change | 2008                | 2007 | Change |
| <b>Unitized wells</b>     |                    |      |        |                     |      |        |
| Gross                     | 24                 | 31   | -23%   | 252                 | 266  | -5%    |
| Equivalent net (1)        | 0.0                | 0.0  | 0%     | 1.0                 | 0.8  | 25%    |
| <b>Non-unitized wells</b> |                    |      |        |                     |      |        |
| Gross                     | 80                 | 105  | -24%   | 353                 | 354  | 0%     |
| Equivalent net (1)        | 4.0                | 3.9  | 3%     | 15.4                | 16.4 | -6%    |
| <b>Total</b>              |                    |      |        |                     |      |        |
| Gross                     | 104                | 136  | -24%   | 605                 | 620  | -2%    |
| Equivalent net (1)        | 4.0                | 3.9  | 3%     | 16.4                | 17.2 | -5%    |

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

### WORKING INTEREST PROPERTIES

Fourth quarter drilling on working interest properties was significantly lower than last year. We participated in the drilling of 3 (1.1 net) wells with a 100% net success rate. This included 2 (1.0 net) Bakken oil wells, which came on production in December and January 2009.

| DRILLING ON WORKING INTEREST PROPERTIES | Three Months Ended December 31 |            |          |            | Twelve Months Ended December 31 |            |           |            |
|-----------------------------------------|--------------------------------|------------|----------|------------|---------------------------------|------------|-----------|------------|
|                                         | 2008                           |            | 2007     |            | 2008                            |            | 2007      |            |
|                                         | Gross                          | Net        | Gross    | Net        | Gross                           | Net        | Gross     | Net        |
| Oil                                     | 2                              | 1.0        | 9        | 2.1        | 31                              | 6.9        | 30        | 8.1        |
| Natural gas                             | -                              | -          | -        | -          | 9                               | 0.7        | 24        | 0.6        |
| Other                                   | 1                              | 0.1        | -        | -          | 2                               | 0.1        | -         | -          |
| <b>Total</b>                            | <b>3</b>                       | <b>1.1</b> | <b>9</b> | <b>2.1</b> | <b>42</b>                       | <b>7.7</b> | <b>54</b> | <b>8.7</b> |

## Results of Operations

Overall, results for the twelve months ended December 31, 2008 reflected higher average commodity prices for the year, while results for the three months ended December 31, 2008 reflected the steep decline in commodity prices in the final quarter of 2008.

In the fourth quarter of 2008, cash provided by operating activities increased 28%, while funds generated from operations declined 17% due to changes in working capital. See Components of Working Capital. Net income was lower in the fourth quarter, due to lower revenues.

Cash provided by operating activities rose 50% in the twelve months ended December 31, 2008, reflecting higher realized prices, partly offset by lower production year over year. Funds generated from operations increased 42%. Similarly, net income improved substantially, to \$110 million from a loss of \$1.2 million in 2007. The loss in 2007 included a \$47.6 million non-cash provision for future income tax following the enactment of the legislation to tax certain publicly-traded specified investment flow-through (SIFT) entities.

| FUNDS GENERATED FROM<br>OPERATIONS AND NET INCOME<br>(\$000s, except as noted) | Three Months Ended<br>December 31 |        |        | Twelve Months Ended<br>December 31 |         |        |
|--------------------------------------------------------------------------------|-----------------------------------|--------|--------|------------------------------------|---------|--------|
|                                                                                | 2008                              | 2007   | Change | 2008                               | 2007    | Change |
| Cash provided by operating activities                                          | 41,672                            | 32,503 | 28%    | 179,252                            | 119,641 | 50%    |
| Changes in non-cash working capital                                            | (14,730)                          | 88     | -      | (7,970)                            | 1,367   | -      |
| Funds generated from operations                                                | 26,942                            | 32,591 | -17%   | 171,282                            | 121,008 | 42%    |
| Per Trust Unit (\$)                                                            | 0.55                              | 0.66   | -17%   | 3.47                               | 2.46    | 41%    |
| Net income (loss)                                                              | 13,374                            | 19,067 | -30%   | 109,956                            | (1,192) | -      |
| Per Trust Unit, basic and diluted (\$)                                         | 0.27                              | 0.39   | -30%   | 2.23                               | (0.02)  | -      |

### PRODUCTION

On a boe basis, our production was down 9% in the fourth quarter (down 8% for the full year), as drilling activity and acquisitions during 2008 were insufficient to offset natural production declines. 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. Royalty interests contributed 71% (2007 Q4 – 70%) of total volumes produced in the fourth quarter.

| AVERAGE DAILY PRODUCTION            | Three Months Ended |        |        | Twelve Months Ended |        |        |
|-------------------------------------|--------------------|--------|--------|---------------------|--------|--------|
|                                     | December 31        |        |        | December 31         |        |        |
|                                     | 2008               | 2007   | Change | 2008                | 2007   | Change |
| <b>Royalty lands</b>                |                    |        |        |                     |        |        |
| Oil (bbls/d)                        | 2,894              | 3,328  | -13%   | 2,922               | 3,188  | -8%    |
| NGL (bbls/d)                        | 296                | 203    | 46%    | 259                 | 252    | 3%     |
| Natural gas (Mcf/d)                 | 13,800             | 15,055 | -8%    | 14,196              | 14,310 | -1%    |
| Oil equivalent (boe/d)              | 5,490              | 6,040  | -9%    | 5,546               | 5,825  | -5%    |
| <b>Working interest properties</b>  |                    |        |        |                     |        |        |
| Oil (bbls/d)                        | 1,671              | 1,907  | -12%   | 1,646               | 1,846  | -11%   |
| NGL (bbls/d)                        | 92                 | 58     | 58%    | 78                  | 81     | -4%    |
| Natural gas (Mcf/d)                 | 3,157              | 3,517  | -10%   | 3,203               | 4,393  | -27%   |
| Oil equivalent (boe/d)              | 2,289              | 2,551  | -10%   | 2,258               | 2,659  | -15%   |
| <b>Total Trust</b>                  |                    |        |        |                     |        |        |
| Oil (bbls/d)                        | 4,565              | 5,235  | -13%   | 4,568               | 5,034  | -9%    |
| NGL (bbls/d)                        | 388                | 261    | 49%    | 337                 | 333    | 1%     |
| Natural gas (Mcf/d)                 | 16,957             | 18,572 | -9%    | 17,399              | 18,703 | -7%    |
| Oil equivalent (boe/d)              | 7,779              | 8,591  | -9%    | 7,804               | 8,484  | -8%    |
| Number of days in period (days)     | 92                 | 92     | 0%     | 366                 | 365    | 0%     |
| Total volumes during period (Mboe)  | 716                | 790    | -9%    | 2,856               | 3,097  | -8%    |
| <b>Potash production (tonnes/d)</b> | <b>9.9</b>         | 15.4   | -36%   | <b>11.9</b>         | 14.2   | -16%   |

## 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 of directors.

## BENCHMARK 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. AECO natural gas prices were 13% higher than the fourth quarter last year. However, adequate inventories and lower weather-related demand put downward pressure on natural gas prices through the fourth quarter.

| AVERAGE BENCHMARK PRICES <sup>(1)</sup>  | Three Months Ended |        |        | Twelve Months Ended |        |        |
|------------------------------------------|--------------------|--------|--------|---------------------|--------|--------|
|                                          | December 31        |        |        | December 31         |        |        |
|                                          | 2008               | 2007   | Change | 2008                | 2007   | Change |
| WTI crude oil (US\$/bbl)                 | 58.69              | 90.68  | -35%   | 99.64               | 72.31  | 38%    |
| US\$/Cdn\$ exchange rate                 | 0.8250             | 1.0188 | -19%   | 0.9428              | 0.9352 | 1%     |
| Edmonton Par crude oil (Cdn\$/bbl)       | 63.21              | 86.42  | -27%   | 102.16              | 76.35  | 34%    |
| Light/heavy oil differential (Cdn\$/bbl) | 13.72              | 29.37  | -53%   | 17.76               | 22.83  | -22%   |
| Bow River/Hardisty (Cdn\$/bbl)           | 49.49              | 57.05  | -13%   | 84.40               | 53.52  | 58%    |
| AECO natural gas (Cdn\$/Mcf)             | 6.78               | 6.00   | 13%    | 8.13                | 6.61   | 23%    |

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

## REALIZED PRICES

Our average selling prices reflect product quality and transportation differences from benchmark prices. On a boe basis, our average price realizations were 8% lower in the fourth quarter of 2008 and 44% higher for the year. As approximately 33% 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 |        |        | Twelve Months Ended |        |        |
|-------------------------|--------------------|--------|--------|---------------------|--------|--------|
|                         | December 31        |        |        | December 31         |        |        |
|                         | 2008               | 2007   | Change | 2008                | 2007   | Change |
| Oil (\$/bbl)            | 49.82              | 58.93  | -15%   | 83.45               | 54.38  | 53%    |
| NGL (\$/bbl)            | 48.28              | 50.85  | -5%    | 67.60               | 53.53  | 26%    |
| Oil and NGL (\$/bbl)    | 49.70              | 58.55  | -15%   | 82.36               | 54.33  | 52%    |
| Natural gas (\$/Mcf)    | 6.84               | 6.07   | 13%    | 8.15                | 6.47   | 26%    |
| Oil equivalent (\$/boe) | 46.55              | 50.57  | -8%    | 69.93               | 48.63  | 44%    |
| Potash (\$/tonne)       | 921.89             | 229.49 | 302%   | 613.33              | 225.28 | 172%   |

## Revenue

Gross revenue declined 15% in the fourth quarter of 2008 due to lower realized prices and lower production volumes. For the full year, revenue was 35% higher, due to higher average commodity prices, partly offset by lower production.

| REVENUE                                        | Three Months Ended |         |        | Twelve Months Ended |         |        |
|------------------------------------------------|--------------------|---------|--------|---------------------|---------|--------|
|                                                | December 31        |         |        | December 31         |         |        |
|                                                | 2008               | 2007    | Change | 2008                | 2007    | Change |
| (\$000s)                                       |                    |         |        |                     |         |        |
| Gross revenue                                  | 34,461             | 40,511  | -15%   | 204,116             | 152,184 | 34%    |
| Royalty and mineral tax expense <sup>(1)</sup> | (1,287)            | (1,293) | 0%     | (6,616)             | (6,263) | 6%     |
| Net revenue                                    | 33,174             | 39,218  | -15%   | 197,500             | 145,921 | 35%    |

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

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

| GROSS REVENUE VARIANCES<br>(\$000s) | Three Months Ended<br>December 31 |               | Twelve Months Ended<br>December 31 |               |
|-------------------------------------|-----------------------------------|---------------|------------------------------------|---------------|
|                                     | 2008 vs. 2007                     | 2007 vs. 2006 | 2008 vs. 2007                      | 2007 vs. 2006 |
|                                     | <b>Oil and NGL</b>                |               |                                    |               |
| Production increase (decrease)      | (2,482)                           | 913           | (13,510)                           | 2,872         |
| Price increase (decrease)           | (4,477)                           | 7,124         | 55,199                             | 7,776         |
| Net increase (decrease)             | (6,959)                           | 8,037         | 41,689                             | 10,648        |
| <b>Natural gas</b>                  |                                   |               |                                    |               |
| Production increase (decrease)      | (1,016)                           | 365           | (3,738)                            | (1,028)       |
| Price increase (decrease)           | 1,316                             | (125)         | 11,473                             | (486)         |
| Net increase (decrease)             | 300                               | 240           | 7,735                              | (1,514)       |
| <b>Other (1)</b>                    | 609                               | 20            | 2,508                              | (17)          |
| Gross revenue increase (decrease)   | (6,050)                           | 8,297         | 51,932                             | 9,117         |

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

## Expenses

### ROYALTY EXPENSE AND MINERAL TAX

Royalty expense and mineral tax includes all Crown charges and royalty payments to third parties. Crown royalty rates are tied to commodity prices and production volumes. The majority of our 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. Mineral taxes recorded in 2007 included approximately \$250,000 that related to 2006.

| ROYALTY EXPENSE AND<br>MINERAL TAX (1)<br>(\$000s, except as noted) | Three Months Ended<br>December 31  |        |        | Twelve Months Ended<br>December 31 |       |        |
|---------------------------------------------------------------------|------------------------------------|--------|--------|------------------------------------|-------|--------|
|                                                                     | 2008                               | 2007   | Change | 2008                               | 2007  | Change |
|                                                                     | <b>Working interest properties</b> |        |        |                                    |       |        |
| Crown royalties                                                     | 945                                | 1,042  | -9%    | 4,488                              | 4,258 | 5%     |
| Third party royalties                                               | 235                                | 198    | 19%    | 1,145                              | 745   | 54%    |
| Mineral tax                                                         | 106                                | 57     | 86%    | 445                                | 252   | 77%    |
| Working interest properties                                         | 1,286                              | 1,297  | -1%    | 6,078                              | 5,255 | 16%    |
| Per boe (\$)                                                        | 6.11                               | 5.53   | 10%    | 7.36                               | 5.41  | 36%    |
| <b>Royalty lands</b>                                                |                                    |        |        |                                    |       |        |
| Crown royalties                                                     | -                                  | -      | -      | -                                  | -     | -      |
| Third party royalties                                               | -                                  | -      | -      | -                                  | -     | -      |
| Mineral tax                                                         | 1                                  | (4)    | -125%  | 538                                | 1,008 | -47%   |
| Royalty lands                                                       | 1                                  | (4)    | -125%  | 538                                | 1,008 | -47%   |
| Per boe (\$)                                                        | -                                  | (0.01) | -120%  | 0.27                               | 0.47  | -44%   |
| <b>Total Trust</b>                                                  | 1,287                              | 1,293  | 0%     | 6,616                              | 6,263 | 6%     |
| Per boe (\$)                                                        | 1.80                               | 1.64   | 10%    | 2.32                               | 2.02  | 15%    |

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

**OPERATING EXPENSES**

Because certain portions of operating expenses are fixed costs, operating costs per boe are highly variable to production volumes. On working interest properties, operating costs per boe were 36% higher in the fourth quarter of 2008 (20% higher for the full year) because of lower production, higher fuel costs, and continued inflationary pressures.

| OPERATING EXPENSES                   | Three Months Ended |       |        | Twelve Months Ended |        |        |
|--------------------------------------|--------------------|-------|--------|---------------------|--------|--------|
|                                      | December 31        |       |        | December 31         |        |        |
|                                      | 2008               | 2007  | Change | 2008                | 2007   | Change |
| Working interest properties (\$000s) | 3,015              | 2,479 | 22%    | 11,299              | 11,076 | 2%     |
| Per boe (\$)                         | 14.31              | 10.56 | 36%    | 13.67               | 11.41  | 20%    |
| Royalty lands (\$000s) (1)           | -                  | -     | -      | -                   | -      | -      |
| Per boe (\$)                         | -                  | -     | -      | -                   | -      | -      |
| Total operating expenses (\$000s)    | 3,015              | 2,479 | 22%    | 11,299              | 11,076 | 2%     |
| Total Trust (\$/boe)                 | 4.21               | 3.14  | 34%    | 3.96                | 3.58   | 11%    |

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

**GENERAL AND ADMINISTRATIVE EXPENSES (G&A)**

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. G&A expenses totalled \$1.6 million in the fourth quarter, including \$1.1 million charged by the Manager for time and direct costs incurred on behalf of the Trust.

| G&A EXPENSES               | Three Months Ended |       |        | Twelve Months Ended |       |        |
|----------------------------|--------------------|-------|--------|---------------------|-------|--------|
|                            | December 31        |       |        | December 31         |       |        |
|                            | 2008               | 2007  | Change | 2008                | 2007  | Change |
| G&A expenses (\$000s)      | 1,574              | 1,425 | 10%    | 6,790               | 5,854 | 16%    |
| Per boe (\$)               | 2.20               | 1.80  | 22%    | 2.38                | 1.89  | 26%    |
| As a percentage of revenue | 4.6%               | 3.5%  | 31%    | 3.3%                | 3.8%  | -13%   |

**UNIT BASED COMPENSATION**

The Trust pays a portion of the costs associated with a long-term incentive compensation plan for employees of the Manager (the Manager's LTIP). For the three months ended December 31, 2008, Freehold recovered \$893,000 (2007 – expensed \$225,000) as unit based compensation. The total recovered for the twelve month period ended December 31, 2008 was \$203,000 (2007 – expensed \$360,000). The liability is estimated at the end of each quarter based on the quarter end Trust Unit price and performance factors, and the related compensation charges are recognized over the three-year vesting period. Unit based compensation was higher in 2008 because it included three years of LTIP grants, while the recovery in the fourth quarter reflected a lower closing price at quarter end. At December 31, 2008, Freehold recorded \$120,000 as a deferred long-term compensation asset representing the portion of the LTIP liability not yet charged to earnings. In addition, Freehold accrued \$243,000 as a long-term liability and \$83,000 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. For the three months ended December 31, 2008, Freehold expensed \$32,000 of unit based compensation with a corresponding increase to contributed surplus (2007 – \$17,000). 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.

**UNIT BASED COMPENSATION**

|                                    | Three Months Ended |      |        | Twelve Months Ended |      |        |
|------------------------------------|--------------------|------|--------|---------------------|------|--------|
|                                    | December 31        |      |        | December 31         |      |        |
|                                    | 2008               | 2007 | Change | 2008                | 2007 | Change |
| Manager's long-term incentive plan | (893)              | 225  | -497%  | (203)               | 366  | -155%  |
| Deferred trust unit plan           | 32                 | 17   | 88%    | 300                 | 265  | 13%    |
| Unit based compensation            | (861)              | 242  | -456%  | 97                  | 631  | -85%   |
| Per boe (\$)                       | (1.20)             | 0.31 | -487%  | 0.03                | 0.20 | -85%   |
| As a percentage of revenue         | -2.5%              | 0.6% | -517%  | 0.0%                | 0.4% | -100%  |

**INTEREST EXPENSES**

Interest expense declined 46% in the fourth quarter of 2008 due to lower interest rates and lower debt levels as excess cash was temporarily applied to debt repayment prior to distribution to Unitholders on January 15, 2009. In the third quarter of 2007, we increased debt by \$79 million to fund royalty acquisitions.

**INTEREST EXPENSES**

|                             | Three Months Ended |       |        | Twelve Months Ended |       |        |
|-----------------------------|--------------------|-------|--------|---------------------|-------|--------|
|                             | December 31        |       |        | December 31         |       |        |
|                             | 2008               | 2007  | Change | 2008                | 2007  | Change |
| Net interest expense (000s) | 1,391              | 2,554 | -46%   | 7,039               | 7,005 | 0%     |
| Per boe (\$)                | 1.94               | 3.23  | -40%   | 2.46                | 2.26  | 9%     |

**DEPLETION AND DEPRECIATION AND ACCRETION OF ASSET RETIREMENT OBLIGATION**

Oil and gas properties and royalty interests, including the cost of production equipment, future capital costs associated with proved reserves, and the capitalized portion of asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties payable. See Critical Accounting Estimates. Reserves are independently evaluated every year as at December 31. For the first three quarters of 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 product quality, transportation, and contract differences.

**DEPLETION, DEPRECIATION AND ACCRETION EXPENSES**

| (\$000s, except as noted)                            | As at December 31 |        |        |
|------------------------------------------------------|-------------------|--------|--------|
|                                                      | 2008              | 2007   | Change |
| Depletion and depreciation                           | 67,948            | 72,400 | -6%    |
| Accretion of asset retirement obligation             | 384               | 266    | 44%    |
| Total depletion, depreciation and accretion expenses | 68,332            | 72,666 | -6%    |
| Per boe (\$)                                         | 23.92             | 23.47  | 2%     |

**MANAGEMENT FEES**

The quarterly management fee, which is paid in Trust Units, was 35,654 Trust Units for the fourth quarter of 2008, unchanged from 2007. The ascribed value was 33% lower because of a lower Trust Unit price at the end of the fourth quarter of 2008.

| MANAGEMENT FEES<br>(Paid in Trust Units)         | Three Months Ended |        |        | Twelve Months Ended |         |        |
|--------------------------------------------------|--------------------|--------|--------|---------------------|---------|--------|
|                                                  | December 31        |        |        | December 31         |         |        |
|                                                  | 2008               | 2007   | Change | 2008                | 2007    | Change |
| Trust Units issued in payment of management fees | 35,654             | 35,654 | 0%     | 142,616             | 142,616 | 0%     |
| Ascribed value (\$000s) (1)                      | 374                | 556    | -33%   | 2,482               | 2,130   | 17%    |
| Per boe (\$)                                     | 0.52               | 0.70   | -26%   | 0.87                | 0.69    | 26%    |

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

**Operating Netback**

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. Our focus on royalties represents a conservative departure from owning traditional oil and gas assets. A royalty interest shares in production revenue without incurring the operational costs, risks, and responsibilities typically associated with oil and gas operations. The following table demonstrates the advantage of our royalty lands, production from which yields higher operating netbacks than our working interest properties.

| NETBACK ANALYSIS<br>(\$ per boe)    | Twelve months ended December 31, 2008 |                  |             |
|-------------------------------------|---------------------------------------|------------------|-------------|
|                                     | Royalty Interest                      | Working Interest | Total Trust |
|                                     | Lands                                 | Properties       |             |
| 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)    |
| Operating netback                   | 140,749                               | 45,452           | 186,201     |

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

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

On a per boe basis, our operating netback for the fourth quarter of 2008 was 9% lower than last year, due to lower commodity prices and higher operating expenses. For the twelve months ended December 31, 2008, our netback was 50% higher, mainly due to exceptionally high commodity prices during the first nine months of the year.

| OPERATING NETBACK<br>(\$/boe)       | Three Months Ended |        |        | Twelve Months Ended |        |        |
|-------------------------------------|--------------------|--------|--------|---------------------|--------|--------|
|                                     | December 31        |        |        | December 31         |        |        |
|                                     | 2008               | 2007   | Change | 2008                | 2007   | Change |
| Gross revenue (1)                   | 48.15              | 51.25  | -6%    | 71.46               | 49.14  | 45%    |
| Royalty expense and mineral tax (2) | (1.80)             | (1.64) | 10%    | (2.32)              | (2.02) | 15%    |
| Operating expenses                  | (4.21)             | (3.14) | 34%    | (3.96)              | (3.58) | 11%    |
| Operating netback                   | 42.14              | 46.47  | -9%    | 65.18               | 43.54  | 50%    |

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

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

## Distributions

As a result of higher average commodity prices during 2008, distributions for 2008 reached a record \$2.91 per Trust Unit, more than 50% higher than in 2007. From inception to December 31, 2008, the Trust has distributed \$724 million (\$19.13 per Trust Unit) to Unitholders.

We declared distributions of \$1.10 per Trust Unit in the fourth quarter, nearly double the amount paid last year. 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.

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.

| ACCUMULATED DISTRIBUTIONS                               | Three Months Ended |         | Twelve Months Ended |         |
|---------------------------------------------------------|--------------------|---------|---------------------|---------|
|                                                         | December 31        |         | December 31         |         |
|                                                         | 2008               | 2007    | 2008                | 2007    |
| <b>Distributions declared (\$000s)</b>                  | <b>54,387</b>      | 28,096  | <b>143,749</b>      | 94,545  |
| Accumulated, beginning of period                        | <b>670,031</b>     | 552,573 | <b>580,669</b>      | 486,124 |
| Accumulated, end of period                              | <b>724,418</b>     | 580,669 | <b>724,418</b>      | 580,669 |
| <b>Distributions per Trust Unit (\$) <sup>(1)</sup></b> | <b>1.10</b>        | 0.57    | <b>2.91</b>         | 1.92    |
| Accumulated, beginning of period                        | <b>18.03</b>       | 15.65   | <b>16.22</b>        | 14.30   |
| Accumulated, end of period                              | <b>19.13</b>       | 16.22   | <b>19.13</b>        | 16.22   |

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

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.

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 \$13.7 million for the fourth quarter of 2008 (2007 – \$13.6 million) and \$61.9 million (2007 – \$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                                                       | Three Months Ended |        | Twelve Months Ended |         |
|-----------------------------------------------------------------------------|--------------------|--------|---------------------|---------|
|                                                                             | December 31        |        | December 31         |         |
|                                                                             | 2008               | 2007   | 2008                | 2007    |
| (\$000s)                                                                    |                    |        |                     |         |
| Cash provided by operating activities                                       | <b>41,672</b>      | 32,503 | <b>179,252</b>      | 119,641 |
| Net income (loss)                                                           | <b>13,374</b>      | 19,067 | <b>109,956</b>      | (1,192) |
| Distributions declared                                                      | <b>54,387</b>      | 28,096 | <b>143,749</b>      | 94,545  |
| Excess of cash provided by operating activities over distributions declared | <b>(23%)</b>       | 16%    | <b>25%</b>          | 27%     |
| Excess (shortfall) of net income over distributions declared                | <b>(75%)</b>       | (32%)  | <b>(24%)</b>        | (101%)  |

## Liquidity and Capital Resources

### CAPITAL MANAGEMENT

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.

| ACQUISITIONS AND CAPITAL EXPENDITURES<br>(\$000s, except as noted) | Three Months Ended |       |        | Twelve Months Ended |         |        |
|--------------------------------------------------------------------|--------------------|-------|--------|---------------------|---------|--------|
|                                                                    | December 31        |       |        | December 31         |         |        |
|                                                                    | 2008               | 2007  | Change | 2008                | 2007    | Change |
| Property and royalty acquisitions (net)                            | (782)              | 26    | -      | 7,693               | 90,456  | -91%   |
| Capital expenditures                                               | 3,770              | 3,901 | -3%    | 12,992              | 12,167  | 7%     |
| Change in reclamation fund                                         | 71                 | 31    | 129%   | 39                  | (329)   | -112%  |
|                                                                    | 3,059              | 3,958 | -23%   | 20,724              | 102,294 | -80%   |

On July 7, 2008, we closed an acquisition of certain royalty and minor working interests in Alberta for \$8.5 million. The acquisition was effective June 1, 2008 and was funded through existing credit facilities. In the fourth quarter, we also recovered \$0.8 million related to adjustments of prior acquisitions.

Our capital expenditure obligations (with respect to our working interest properties) are deducted from cash provided by operating activities prior to the determination of distributions to Unitholders. 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. We expect to fund distributions and capital expenditures from cash provided by operating activities. However, over the long term, we will continue to fund acquisitions through additional debt and equity.

Our distribution policy includes withholding a portion of cash provided by operating activities for contributions to the reclamation fund to provide a cash reserve for the eventual abandonment of oil and gas properties. 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. Our reclamation fund consists of cash invested in an interest-bearing account and was funded by quarterly cash payments of \$150,000 during 2008. 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.

### WORKING CAPITAL

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 prices changes at each period end. At the end of the fourth quarter of 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**

|                                            | Dec. 31  | Sept. 30 | June 30  | Mar. 31  | Dec. 31  |
|--------------------------------------------|----------|----------|----------|----------|----------|
| (\$000s)                                   | 2008     | 2008     | 2008     | 2008     | 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 <sup>(1)</sup>             | (20,055) | 11,119   | 18,032   | 16,595   | 11,219   |

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

**DEBT ANALYSIS**

We have a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, and a \$15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 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 the end of the fourth quarter, we had \$70 million of available capacity under our credit facilities.

At December 31, 2008, we had no short-term debt outstanding and long-term debt was \$140 million. We had negative working capital of \$20.1 million, resulting in net debt of \$160.1 million. In addition, we had accrued a \$326,000 liability relating to incentive compensation pursuant to the Manager's LTIP, of which \$83,000 was a current liability.

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)              | As at December 31 |         |        |
|-----------------------|-------------------|---------|--------|
|                       | 2008              | 2007    | Change |
| Long-term debt        | 140,000           | 178,000 | -21%   |
| Short-term debt       | -                 | -       | -      |
| Total debt            | 140,000           | 178,000 | -21%   |
| Less: working capital | (20,055)          | 11,219  | -279%  |
| Net debt obligations  | 160,055           | 166,781 | -4%    |

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 <sup>(1)</sup>**

|                                                     | As at December 31 |      |        |
|-----------------------------------------------------|-------------------|------|--------|
|                                                     | 2008              | 2007 | Change |
| Net debt to funds generated from operations (times) | 0.9               | 1.4  | -36%   |
| Net debt to distributions (times)                   | 1.1               | 1.8  | -39%   |
| Distributions to interest expense (times)           | 20.4              | 13.5 | 51%    |
| Net debt to net debt plus equity (%)                | 42%               | 40%  | 5%     |

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

## FUTURE INCOME TAX

The future income tax liability on our Consolidated Balance Sheet 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, this enactment of SIFT tax legislation required 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.

## UNITHOLDERS' CAPITAL

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 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, 2008 and March 11, 2009, there were 49,459,429 Trust Units outstanding. As at December 31, 2008, there were 44,087 deferred trust units outstanding and at March 11, 2009, there were 67,488 deferred trust units outstanding, which are redeemable for an equal number of Trust Units any time after the director's retirement. On January 1, 2009, the Board granted 20,020 deferred trust units to eligible directors of Freehold Resources Ltd. as part of the directors' annual compensation. Each eligible director received 2,860 deferred trust units, and the Chair of the Board received 5,720 deferred trust units.

| TRUST UNITS OUTSTANDING | Three Months Ended |            |        | Twelve Months Ended |            |        |
|-------------------------|--------------------|------------|--------|---------------------|------------|--------|
|                         | December 31        |            |        | December 31         |            |        |
|                         | 2008               | 2007       | Change | 2008                | 2007       | Change |
| Weighted average        |                    |            |        |                     |            |        |
| Basic                   | 49,424,163         | 49,281,547 | 0%     | 49,370,878          | 49,228,411 | 0%     |
| Diluted                 | 49,466,965         | 49,311,402 | 0%     | 49,412,670          | 49,228,411 | 0%     |
| At period end           | 49,459,429         | 49,316,813 | 0%     | 49,459,429          | 49,316,813 | 0%     |

As a result of the Canadian trust taxation legislation passed in June 2007 and effective January 1, 2011, SIFT entities are subject to certain capital growth restrictions referred to as "normal growth" equity guidelines. 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.

## 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 muted 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 in 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 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.

## QUARTERLY REVIEW

|                                            | 2008    |         |         |         | 2007    |         |          |        |
|--------------------------------------------|---------|---------|---------|---------|---------|---------|----------|--------|
|                                            | Q4      | Q3      | Q2      | Q1      | Q4      | Q3      | Q2       | Q1     |
| <b>Financial (\$000s, except as noted)</b> |         |         |         |         |         |         |          |        |
| 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                    |         |         |         |         |         |         |          |        |
| 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 |
| <b>Operating (\$/boe, except as noted)</b> |         |         |         |         |         |         |          |        |
| 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   |
| <b>Benchmark Prices</b>                    |         |         |         |         |         |         |          |        |
| 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   |
| <b>Unit Trading Performance</b>            |         |         |         |         |         |         |          |        |
| 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.

The following table compares our key operating assumptions for 2008 to actual results for the year.

| 2008 KEY OPERATING ASSUMPTIONS                           | 2008           | News          |            | News       |               |            |
|----------------------------------------------------------|----------------|---------------|------------|------------|---------------|------------|
|                                                          | Actual Results | Release Dated | MD&A Dated | MD&A Dated | Release Dated | MD&A Dated |
|                                                          | Mar. 11        | Dec. 16       | Nov. 5     | Aug. 13    | June 12       | May 7      |
|                                                          | 2009           | 2008          | 2008       | 2008       | 2008          | 2008       |
| Average daily production (boe/d)                         | 7,804          | 7,900         | 7,900      | 7,900      | 7,900         | 8,200      |
| Average WTI oil price (US\$/bbl)                         | 99.64          | 100.00        | 102.00     | 116.00     | 114.00        | 100.00     |
| Average light/heavy oil price differential (Cdn\$/bbl)   | 17.76          | 18.00         | 19.00      | 23.00      | 24.00         | 26.00      |
| Average Bow River Hardisty oil price (Cdn\$/bbl)         | 84.40          | 85.00         | 88.00      | 94.00      | 90.00         | 73.00      |
| Average AECO natural gas price (Cdn\$/Mcf)               | 8.13           | 8.10          | 8.15       | 8.90       | 8.60          | 6.85       |
| Average exchange rate (Cdn\$/US\$)                       | 0.94           | 0.94          | 0.94       | 0.99       | 0.99          | 0.99       |
| Average operating costs (\$/boe)                         | 3.96           | 3.85          | 3.85       | 3.85       | 3.85          | 3.85       |
| Average G&A costs (1)                                    | 2.38           | 2.55          | 2.55       | 2.55       | 2.55          | 2.44       |
| Capital expenditures (\$ millions)                       | 13.0           | 12.3          | 12.3       | 10.6       | 10.6          | 10.6       |
| Long-term debt at year end (\$ millions)                 | 140 (2)        | 160           | 165        | 155        | 155           | 155        |
| Weighted average Trust Units outstanding (thousands)     | 49,371         | 49,371        | 49,371     | 49,371     | 49,371        | 49,371     |
| Estimated portion of distributions taxable as income (%) | 96%            | 90-100%       | 90-100%    | 90-100%    | 90-100%       | 90-100%    |

(1) Excludes unit based compensation.

(2) Long-term debt at December 31, 2008 excludes distributions declared on December 16, 2008 (\$0.60 per Trust Unit including an additional distribution of \$0.35 in respect of 2008), which were paid to Unitholders on January 15, 2009; the aggregate amount was reflected as a current liability at year end.

There were no material variances between actual 2008 results and the guidance provided in our 2008 third quarter except for adjustments to commodity price and foreign exchange assumptions to reflect current market conditions and capital expenditure timing differences relating to two wells drilled in the fourth quarter of 2008 rather than in the first quarter of 2009.

## Outlook

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 softening 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 royalty 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 a modest price recovery later in the year.

As a result 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. While these issues may affect our ability to access financing for potential future acquisitions, we are not reliant on debt or equity markets to finance operating activities.

On our working interest properties, we will continue to fund development activities from cash provided by operating activities. We plan to spend approximately \$12 million 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 4-well pilot program using horizontal drilling, staged fracture stimulation and micro seismic technology. Infill drilling is also anticipated at Hayter, Alberta. 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. Our Board has established a distribution policy for the second quarter 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.

## 2009 KEY OPERATING ASSUMPTIONS

|                                                          | MD&A<br>Dated<br>Mar. 11<br>2009 | News<br>Release<br>Dated<br>Jan. 20<br>2009 | News<br>Release<br>Dated<br>Dec. 16<br>2008 |
|----------------------------------------------------------|----------------------------------|---------------------------------------------|---------------------------------------------|
| Average daily production (boe/d)                         | 7,500                            | 7,500                                       | 7,500                                       |
| Average WTI oil price (US\$/bbl)                         | 44.00                            | 38.00                                       | 50.00                                       |
| Average AECO natural gas price (Cdn\$/Mcf)               | 5.00                             | 6.00                                        | 7.00                                        |
| Average exchange rate (Cdn\$/US\$)                       | 0.80                             | 0.80                                        | 0.80                                        |
| Average operating costs (\$/boe)                         | 4.10                             | 4.10                                        | 4.10                                        |
| Average G&A costs (1)                                    | 2.90                             | 2.90                                        | 2.90                                        |
| Capital expenditures (\$ millions)                       | 12.0                             | 16.7                                        | 16.7                                        |
| Long-term debt at year end (\$ millions)                 | 159                              | 159                                         | 159                                         |
| Weighted average Trust Units outstanding (thousands)     | 49,514                           | 49,514                                      | 49,514                                      |
| Estimated portion of distributions taxable as income (%) | 90-100%                          | 90-100%                                     | 90-100%                                     |

(1) Excludes unit based compensation.

There are no material variances between our current guidance and our initial 2009 guidance except for the following:

- We lowered our capital budget for 2009 by \$4.7 million in January; some drilling plans have been deferred as a result of low commodity prices.
- We have adjusted our commodity price assumptions to reflect current market conditions.

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

| Variables                          | Change (+/-)  | Estimated Change in Distributions to Unitholders |                 |
|------------------------------------|---------------|--------------------------------------------------|-----------------|
|                                    |               | (\$000s)                                         | (\$/Trust Unit) |
| WTI crude oil price                | US\$1.00/bbl  | 2,044                                            | 0.04            |
| Light/heavy oil price differential | Cdn\$1.00/bbl | 1,635                                            | 0.03            |
| Natural gas price                  | Cdn\$0.25/Mcf | 1,292                                            | 0.03            |
| Exchange rate (US\$/Cdn\$)         | 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   | 1,603                                            | 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. 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 NRF 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 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 new 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.

## 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.

## 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.

## Changes in Accounting Policies

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:

- our objectives, policies, and processes for managing capital;
- quantitative data about what we regard as capital; and
- 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.

## New Accounting 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.

## Related Party Transactions

We do not operate any of our oil and gas assets, nor do we have any employees. The Manager of the Trust is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). The Manager recovers its costs (see General and Administrative Expenses and Unit Based Compensation) and receives a quarterly management fee paid in Trust Units (see Management Fees).

## Internal Controls

The Chief Executive Officer (CEO) and the Chief Financial Officer (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.

The CEO and CFO believe that the Trust's ICFR provide a reasonable level of assurance with regard to their effectiveness; they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

There were no changes in the Trust's ICFR during the year ended December 31, 2008 that materially affected the Trust's ICFR.

## Consolidated Balance Sheets

| (\$000s) (unaudited)                                                                                               | December 31<br>2008 | December 31<br>2007 |
|--------------------------------------------------------------------------------------------------------------------|---------------------|---------------------|
| <b>Assets</b>                                                                                                      |                     |                     |
| Current assets:                                                                                                    |                     |                     |
| Cash                                                                                                               | \$ 537              | \$ 393              |
| Accounts receivable                                                                                                | 23,261              | 26,802              |
|                                                                                                                    | 23,798              | 27,195              |
| Reclamation fund                                                                                                   | 1,827               | 1,788               |
| Deferred long-term compensation (note 5)                                                                           | 120                 | 697                 |
| Petroleum and natural gas interests, net of accumulated depletion and depreciation of \$450,079 (2007 - \$382,131) | 426,530             | 474,520             |
|                                                                                                                    | \$ 452,275          | \$ 504,200          |
| <b>Liabilities and Unitholders' Equity</b>                                                                         |                     |                     |
| 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 5)                                                        | 83                  | -                   |
|                                                                                                                    | 43,853              | 15,976              |
| Asset retirement obligation                                                                                        | 5,663               | 6,608               |
| Unit based compensation payable (note 5)                                                                           | 243                 | 1,106               |
| Long-term debt (note 3)                                                                                            | 140,000             | 178,000             |
| Future income tax liability                                                                                        | 42,511              | 51,404              |
| Unitholders' equity:                                                                                               |                     |                     |
| Unitholders' capital (note 4)                                                                                      | 567,310             | 564,828             |
| Contributed surplus (note 5)                                                                                       | 722                 | 512                 |
| Deficit                                                                                                            | (348,027)           | (314,234)           |
|                                                                                                                    | 220,005             | 251,106             |
|                                                                                                                    | \$ 452,275          | \$ 504,200          |

See accompanying notes to interim consolidated financial statements.

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

| (Unaudited)<br>(\$000s, except per unit and weighted average data) | Three Months Ended<br>December 31 |                | Year Ended<br>December 31 |                |
|--------------------------------------------------------------------|-----------------------------------|----------------|---------------------------|----------------|
|                                                                    | 2008                              | 2007           | 2008                      | 2007           |
| Revenue:                                                           |                                   |                |                           |                |
| Royalty income and working interest sales                          | \$ 34,461                         | \$ 40,511      | \$ 204,116                | \$ 152,184     |
| Royalty expense and mineral tax                                    | (1,287)                           | (1,293)        | (6,616)                   | (6,263)        |
|                                                                    | <b>33,174</b>                     | <b>39,218</b>  | <b>197,500</b>            | <b>145,921</b> |
| Expenses:                                                          |                                   |                |                           |                |
| Operating                                                          | 3,015                             | 2,479          | 11,299                    | 11,076         |
| General and administrative                                         | 1,574                             | 1,425          | 6,790                     | 5,854          |
| Unit based compensation (note 5)                                   | (861)                             | 242            | 97                        | 631            |
| Interest on long-term debt                                         | 1,391                             | 2,554          | 7,039                     | 7,005          |
| Depletion and depreciation                                         | 16,076                            | 18,601         | 67,948                    | 72,400         |
| Accretion of asset retirement obligation                           | 96                                | 66             | 384                       | 266            |
| Management fee (note 6)                                            | 374                               | 556            | 2,482                     | 2,130          |
|                                                                    | <b>21,665</b>                     | <b>25,923</b>  | <b>96,039</b>             | <b>99,362</b>  |
| Net income before taxes                                            | 11,509                            | 13,295         | 101,461                   | 46,559         |
| Income and capital taxes                                           | 165                               | 81             | 398                       | 179            |
| Future income tax expense (reduction)                              | (2,030)                           | (5,853)        | (8,893)                   | 47,572         |
|                                                                    | <b>(1,865)</b>                    | <b>(5,772)</b> | <b>(8,495)</b>            | <b>47,751</b>  |
| Net income (loss) and comprehensive income (loss)                  | <b>13,374</b>                     | <b>19,067</b>  | <b>109,956</b>            | <b>(1,192)</b> |
| Deficit, beginning of period                                       | (307,014)                         | (305,205)      | (314,234)                 | (218,497)      |
| Distributions declared                                             | (54,387)                          | (28,096)       | (143,749)                 | (94,545)       |
| Deficit, end of period                                             | \$ (348,027)                      | \$ (314,234)   | \$ (348,027)              | \$ (314,234)   |
| Net income (loss) per Trust Unit, basic and diluted                | \$ 0.27                           | \$ 0.39        | \$ 2.23                   | \$ (0.02)      |
| Weighted average number of Trust Units:                            |                                   |                |                           |                |
| Basic                                                              | 49,424,163                        | 49,281,547     | 49,370,878                | 49,228,411     |
| Diluted                                                            | 49,466,965                        | 49,311,402     | 49,412,670                | 49,228,411     |

See accompanying notes to interim consolidated financial statements.

## Consolidated Statements of Cash Flows

| (Unaudited)<br>(\$000s)                      | Three Months Ended<br>December 31 |           | Year Ended<br>December 31 |            |
|----------------------------------------------|-----------------------------------|-----------|---------------------------|------------|
|                                              | 2008                              | 2007      | 2008                      | 2007       |
| Cash provided by (used in):                  |                                   |           |                           |            |
| Operating:                                   |                                   |           |                           |            |
| Net income (loss)                            | \$ 13,374                         | \$ 19,067 | \$ 109,956                | \$ (1,192) |
| Items not involving cash:                    |                                   |           |                           |            |
| Depletion and depreciation                   | 16,076                            | 18,601    | 67,948                    | 72,400     |
| Trust Unit incentive compensation (note 5)   | (861)                             | 242       | 7                         | 631        |
| Future income tax expense (reduction)        | (2,030)                           | (5,853)   | (8,893)                   | 47,572     |
| Accretion of asset retirement obligation     | 96                                | 66        | 384                       | 266        |
| Trust Units issued in lieu of management fee | 374                               | 556       | 2,482                     | 2,130      |
| Expenditures on reclamation                  | (87)                              | (88)      | (602)                     | (799)      |
|                                              | 26,942                            | 32,591    | 171,282                   | 121,008    |
| Changes in non-cash working capital          | 14,730                            | (88)      | 7,970                     | (1,367)    |
|                                              | 41,672                            | 32,503    | 179,252                   | 119,641    |
| Financing:                                   |                                   |           |                           |            |
| Long-term debt                               | (1,000)                           | (1,000)   | (38,000)                  | 78,000     |
| Distributions paid                           | (37,068)                          | (28,091)  | (121,471)                 | (94,524)   |
|                                              | (38,068)                          | (29,091)  | (159,471)                 | (16,524)   |
| Investing:                                   |                                   |           |                           |            |
| Property and royalty acquisitions            | 782                               | (26)      | (7,693)                   | (90,456)   |
| Capital expenditures                         | (3,770)                           | (3,901)   | (12,992)                  | (12,167)   |
| Change in reclamation fund                   | (71)                              | (31)      | (39)                      | 329        |
| Changes in non-cash working capital          | (220)                             | 857       | 1,087                     | (851)      |
|                                              | (3,279)                           | (3,101)   | (19,637)                  | (103,145)  |
| Increase (decrease) in cash                  | 325                               | 311       | 144                       | (28)       |
| Cash, beginning of period                    | 212                               | 82        | 393                       | 421        |
| Cash, end of period                          | \$ 537                            | \$ 393    | \$ 537                    | \$ 393     |

See accompanying notes to interim consolidated financial statements.

# Notes to Interim Consolidated Financial Statements

For the period ended December 31, 2008.

## 1. Significant Accounting Policies

The interim consolidated financial statements of Freehold Royalty Trust (Freehold or the Trust) have been prepared by management in accordance with Canadian generally accepted accounting principles. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2007, except for the new standards regarding financial instruments and capital disclosures, as detailed below. The following disclosure is incremental to the disclosure contained in the notes to the 2007 annual consolidated financial statements. The interim consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes for the year ended December 31, 2007.

### 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 during the transition period, 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. 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.

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<br>(\$000s, except as noted)                           | December 31<br>2008 | December 31<br>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.

##### 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.

##### 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.

**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 three months 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 three months ended December 31, 2008, would have resulted in a corresponding change to net income of approximately \$0.4 million (2007 – \$0.4 million).

## Commodity price risk

- Commodity price risk is the risk that the fair value of future cash flows will fluctuate with changes in commodity prices. Commodity prices for oil and natural gas are influenced by the relationship between the Canadian and U.S. dollar as well as macroeconomic events that dictate the levels of supply and demand. During the three months 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 three months ended December 31, 2008, would have resulted in a corresponding change to net income of approximately \$0.4 million (2007 – \$0.3 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 \$0.4 million (2007 – \$0.4 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 three months period ended December 31, 2008 would have resulted in a corresponding change to net income of approximately \$0.4 million (2007 – \$0.5 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.

**2. Property acquisition**

On July 7, 2008, Freehold closed an acquisition of certain royalty and minor working interests in Alberta for \$8.5 million. The acquisition was effective June 1, 2008 and was funded through existing credit facilities. Freehold also recovered \$0.8 million of prior acquisition adjustments.

### 3. Long-Term Debt

Freehold has a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks, on which \$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.

### 4. Unitholders' Capital

|                                  | December 31, 2008 |                    | December 31, 2007 |                    |
|----------------------------------|-------------------|--------------------|-------------------|--------------------|
|                                  | Units             | Amount<br>(\$000s) | Units             | Amount<br>(\$000s) |
| Balance, beginning of period     | 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 period           | 49,459,429        | 567,310            | 49,316,813        | 564,828            |

For the purposes 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) 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, 2008, Freehold recovered \$893,000 (2007 – expensed \$225,000) as unit based compensation. 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

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, 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. For the three months ended December 31, 2008, Freehold expensed \$32,000 of unit based compensation with a corresponding increase to contributed surplus (2007 – \$17,000). 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<br>(\$000s)           | December 31<br>2008 | December 31<br>2007 |
|-------------------------------------------|---------------------|---------------------|
| Balance, beginning of period              | 512                 | 247                 |
| Trust Unit incentive compensation expense | 210                 | 265                 |
| Balance, end of period                    | 722                 | 512                 |

## 6. Related Party Transactions

For the three months ended December 31, 2008, Freehold issued 35,654 Trust Units as management fee to the Manager, Rife Resources Ltd., (2007 – 35,654 Trust Units) pursuant to a management agreement. The ascribed value of \$374,000 (2007 – \$556,000) is based on the closing price of the Trust Units on the last trading day of the quarter. The total Trust Units issued for the year ended December 31, 2008 was 142,616 Trust Units (2007 – 142,616) with an ascribed value of \$2,482,000 (2007 – \$2,130,000).

For the three months ended December 31, 2008, the Manager charged the Trust \$1,067,000 in general and administrative costs (2007 – \$893,000). The total for the year ended December 31, 2008 was \$5,303,000 (2007 – \$4,390,000). At December 31, 2008, there was \$nil (2007 – \$298,000) in accounts payable and accrued liabilities relating to these costs. The transactions were in the normal course of operations and were measured at the exchange amount, which was the amount of consideration established and agreed to by the Trust and the Manager.

## 7. Supplemental Cash Flow Disclosure

| CASH EXPENSES PAID<br>(\$000s) | Three Months Ended<br>December 31 |       | Year Ended<br>December 31 |       |
|--------------------------------|-----------------------------------|-------|---------------------------|-------|
|                                | 2008                              | 2007  | 2008                      | 2007  |
| Interest                       | 1,118                             | 2,517 | 6,753                     | 7,256 |
| Taxes                          | 73                                | (199) | 329                       | (690) |

## 8. Subsequent Event

On January 20, 2009, the Board of Directors approved a decrease in the distribution rate to \$0.10 per Trust Unit. This was effective for the January distribution payable February 15 to Unitholders of record on January 31, 2009.

## Corporate Information

### BOARD OF DIRECTORS

**William W. Siebens**  
President and Chief Executive Officer  
Candor Investments Ltd.

**D. Nolan Blades** (1)(2)(3)(5)  
President  
Sunny Gables Holdings Ltd.

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

**Tullio Cedraschi** (3)(4)  
Corporate Director

**Peter T. Harrison** (1)(2)(3)(5)  
Senior Vice-President  
Montrusco Bolton Investments Inc.

**Russell J. Hiscock**  
President and Chief Executive Officer  
CN Investment Division

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

**David J. Sandmeyer**  
President and Chief Executive Officer  
Rife Resources Ltd.

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

### STOCK EXCHANGE

Toronto Stock Exchange  
Trading Symbol: FRU.UN

### TRUSTEE AND TRANSFER AGENT

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

### OFFICERS

**William W. Siebens**  
Chair of the Board

**David J. Sandmeyer**  
President and Chief Executive Officer

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

**Garry W. Bieber**  
Vice-President, Production

**J. Frank George**  
Vice-President, Exploitation

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

**Michael J. Okrusko**  
Vice-President, Land

**Michael J. Mogan**  
Controller

**Karen C. Taylor**  
Manager, Investor Relations and  
Corporate Secretary

### HEAD OFFICE

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

### INVESTOR RELATIONS

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

### WEBSITE

www.freeholdtrust.com

### 2008 FOURTH QUARTER TRADING SUMMARY

High – \$18.43  
Low – \$9.15  
Close – \$10.49  
Volume – 10.5 million  
Trust Units Outstanding – 49.5 million  
Market Capitalization – \$519 million  
(December 31)

### LEGAL COUNSEL

Burnet Duckworth & Palmer, LLP  
Calgary, Alberta

### AUDITORS

KPMG, LLP  
Calgary, Alberta

### BANKERS

Canadian Imperial Bank of  
Commerce  
Calgary, Alberta

Royal Bank of Canada  
Calgary, Alberta

The Toronto-Dominion Bank  
Calgary, Alberta

### RESERVE EVALUATORS

Trimble Engineering Associates Ltd.  
Calgary, Alberta

### 2008 FOURTH QUARTER DISTRIBUTIONS DECLARED

| Record Date   | Payment Date  | Per Trust Unit                               |
|---------------|---------------|----------------------------------------------|
| Oct 31, 2008  | Nov. 15, 2008 | \$0.25                                       |
| Nov. 30, 2008 | Dec. 15, 2008 | \$0.25                                       |
| Dec. 31, 2008 | Jan. 15, 2009 | <u>\$0.60<sup>(1)</sup></u><br><u>\$1.10</u> |

(1) Includes additional \$0.35 per Trust Unit distribution related to 2008.

Tax information and historical distributions are available on our website.