



Renewal Annual Information Form

For the year ended December 31, 2003

May 10, 2004

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Forward-Looking Statements

This AIF contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Trust's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. A discussion of some of these risks is included under "Risk Factors". 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. Actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. No assurance can be given that any of the events anticipated will transpire or occur, or if any of them do so, what benefits the Trust will derive from them. The Trust disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

GLOSSARY OF TERMS

In this Annual Information Form, the following terms shall have the meanings set forth below, unless otherwise indicated:

“**Acquireco**” means the one or more corporations, which may be formed by the Trust as wholly owned subsidiaries to acquire corporate facilities and other types of oil and natural gas related acquisitions in addition to Canadian resource properties.

“**Acquireco Distributions**” means cash distributions made to the Trust from Acquireco, which distributions will be distributed to Unitholders, after deduction of all required deductions.

“**Acquisition Fee**” means the acquisition fees payable to the Manager pursuant to the Management Agreement.

“**Additional Properties**” means working interests in oil and natural gas rights acquired by Freehold Resources from time to time.

“**Additional Royalties**” means royalty interests in oil and natural gas rights acquired by the Trust from time to time.

“**ARC**” means credits and rebates in respect of Crown royalties which are paid or credited by the Crown, including those paid or credited under the Alberta Corporate Tax Act which are commonly known as “Alberta Royalty Credits”.

“**Asset Value**” means, for any property at any time, the present value of all of the estimated pre-tax net cash flow from the net proved plus probable reserves shown in the most recent engineering report relating to such property, discounted at 10% and using forecast price and cost assumptions.

“**CN Pension Trust Funds**” means the Canadian National Railway System Pension Trust Fund.

“**Canpar**” means Canpar Holdings Ltd.

“**Cash Distribution Date**” means the date Distributions to Unitholders are paid, being the 15th day following any Record Date.

“**COGE Handbook**” means the “Canadian Oil and Gas Evaluation Handbook” prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

“**Debt Service Charges**” means all interest and principal repayments and other costs, expenses and disbursements relating to the borrowing of funds by the Trust and Freehold Resources.

“**Deferred Purchase Price Obligation**” means the ongoing obligation of the Trust to pay to Freehold Resources, to the extent of the Trust’s available funds, an amount equal up to 99% of the cost of, or any amount outstanding in respect of money borrowed by Freehold Resources to acquire, any additional “Canadian resource property” (as defined in the Tax Act) acquired by Freehold Resources and of the cost of, or any amount borrowed by Freehold Resources to fund, certain designated capital expenditures as partial consideration for the Freehold Resources Royalty. See “Description of Properties – Freehold Resources Royalty – Deferred Purchase Price Obligation”.

“**Distributions to Unitholders**” means, for any particular period, the HB Lands Royalties, Additional Royalties, the Freehold Resources Royalty and Acquireco Distributions received by the Trust plus the interest income from Permitted Investments and ARC, if any, received by the Trust less the Trust’s share of Crown royalties (other than Crown royalties which are deducted in the computation of the Royalty), expenses and withholding payable by the Trust and less other amounts reasonably determined by Freehold Resources to be retained for the purposes of the Trust.

“**Freehold Resources**” means Freehold Resources Ltd., which acquired the Working Interest Properties and granted the Freehold Resources Royalty to the Trust.

“**Freehold Resources Notes**” means promissory notes issued by Freehold Resources in series pursuant to a note indenture in the principal amount of the Market Redemption Price or Appraised Redemption Price of the Trust Units to be redeemed in consideration for a portion of the royalty having a fair market value equal to such principal amount on the following terms and conditions: (a) unsecured and bearing interest at the lessor of: (i) the interest paid on 2

year Government of Canada bonds minus 2%, or (ii) 6% per annum payable monthly in arrears on the 20th day of the next following month; (b) subordinate to all senior indebtedness which includes all indebtedness for borrowed money or owing in respect of property purchases on any default in payment of any such senior indebtedness, and to all trade debt of Freehold Resources or any subsidiary of Freehold Resources or the Trust on any creditor proceedings such as bankruptcy, liquidation or insolvency; (c) subject to earlier prepayment, being due and payable on the 15th anniversary of the date of issuance and (d) in an aggregate principal amount not exceeding \$500 million.

“Freehold Resources Properties” means the working, royalty or other interest of Freehold Resources from time to time in any oil and natural gas rights, tangibles and miscellaneous interests, including the Working Interest Properties and Additional Properties.

“Freehold Resources Royalty” means the royalty payable by Freehold Resources to the Trust pursuant to the Freehold Resources Royalty Agreement which equals 99% of Freehold Resources Royalty Income.

“Freehold Resources Royalty Agreement” means the agreement regarding the creation and sale of the Freehold Resources Royalty dated November 25, 1996 between Freehold Resources and the Trustee as trustee for and on behalf of the Trust, as amended from time to time.

“Freehold Resources Royalty Income” in respect of any period for which Freehold Resources Royalty Income is calculated means: (a) the amount received in such period in respect of the sale of Petroleum Substances collected from the Freehold Resources Properties (including the share reserved to the Crown) and any other revenue received in such period other than the proceeds from the sale of the Freehold Resources Properties; less (b) the aggregate of the following costs and expenses paid in such period: (i) all costs and expenses (including both operating costs and capital costs) in respect of the Freehold Resources Properties, except to the extent that such costs or expenses are funded by borrowing and in the case of capital costs, except to the extent designated as Deferred Purchase Price Obligations, including, without limitation, the costs of gathering, compressing, processing, transporting and marketing all Petroleum Substances produced from the Freehold Resources Properties and all other amounts paid to third parties which are calculated with reference to production from the Freehold Resources Properties including, without limitation, gross overriding royalties and lessor’s royalties, but excepting Crown royalties and other Crown charges; (ii) income, capital and other direct taxes in respect of the Freehold Resources Properties; (iii) Debt Service Charges; (iv) General and Administrative Costs to the extent not paid from the residual income of Freehold Resources; (v) net contributions to Freehold Resources’ reclamation fund; (vi) the amount paid to the Trust to purchase Trust Units to satisfy its obligations under the Management Agreement and (vii) all other costs and expenses relating to the Freehold Resources Properties. Any income derived from Freehold Resources Properties which are not working interests in “Canadian resource properties” (as defined in the Tax Act), will not be included as Freehold Resources Royalty Income and will be used to defray capital expenditures and other expenses of Freehold Resources.

“General and Administrative Costs” means the amount in aggregate representing all expenditures and costs incurred under the Management Agreement in respect of Freehold Resources, the Trust or the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty or in the management and administration of Freehold Resources, the Trust or the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty including, without limitation: (a) all reasonable costs and expenses relating to Freehold Resources, the Trust and the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty paid to third parties by or on behalf of Freehold Resources, the Trust or their affiliates, including, without limitation, Trustee’s fees; and (b) all reasonable costs and expenses incurred specifically for Freehold Resources or the Trust relating to Freehold Resources, the Trust or the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty including, without limitation, auditing, accounting, bookkeeping, rent and other leasehold expenses, legal, land administration, engineering, travel, telephone, data processing, reporting, executive and management time, salaries and all of those costs and expenses incurred by the Manager in discharging its obligations under the Management Agreement in respect of Freehold Resources, the Trust or the HB Lands Royalties, Additional Royalties or the Freehold Resources Royalty (other than the Acquisition Fee).

“Gross” means:

- in relation to production and reserves, the Trust’s working interest (operating and non-operating) share before deduction of royalties and without including any royalty interests of the Trust;
- in relation to wells, the total number of wells in which the Trust has an interest; and
- in relation to properties, the total area of properties in which the Trust has an interest.

“HB Lands” means the lands from which the HB Lands Royalties are derived.

“HB Lands Royalties” means the royalties representing the right to receive revenue from the HB Lands from all formations to the base of the deepest formation which was producing Petroleum Substances or potash at January 1, 1996 with respect to each mineral title or royalty assumption property acquired by the Trust from Canpar pursuant to the Royalty Sale Agreement.

“Management Agreement” means the agreement dated November 25, 1996 between the Manager, Freehold Resources and the Trustee for and on behalf of the Trust pursuant to which the Manager agreed to provide management services to Freehold Resources and the Trust. See “The Manager – Management Agreement”.

“Management Fees” means the fees payable to the Manager pursuant to the Management Agreement.

“Manager” means Rife Resources Management Ltd.

“Net” means:

- in relation to production and reserves, the Trust’s working and non-working interest (operating and non-operating) share after deduction of royalty obligations, plus the Trust’s royalty interests.
- in relation to wells, the number of wells obtained by aggregating the Trust’s working interest in each of its gross wells; and
- in relation to the Trust’s interest in a property, the total area in which the Trust has an interest multiplied by the working interest owned by the Trust.

“NI-51-101” means National Instrument 51-101 *Standard of Disclosure for Oil and Gas Activities*.

“Permitted Investments” means: (i) loan advances to Freehold Resources; (ii) interest-bearing accounts of a Canadian chartered bank or the Trustee; (iii) guaranteed investment certificates issued by a Canadian chartered bank or the Trustee; (iv) investment grade money market instruments or funds; (v) Government of Canada Treasury Bills; and (vi) Additional Royalties which are direct royalty interests in petroleum and natural gas rights; provided that an investment will not be a Permitted Investment if it would result in the Trust holding more than 8% of its assets at any particular time in the securities of any person other than the Government of Canada, any province or any municipality.

“Petroleum Substances” means petroleum, natural gas and related hydrocarbons (except coal) including, without limitation, all liquid hydrocarbons, and all other substances, including sulphur, whether gaseous, liquid or solid and whether hydrocarbon or not, produced in association with such petroleum, natural gas or related hydrocarbons.

“Potash Report” means the report dated February 12, 2004 prepared by the Manager, evaluating the potash reserves attributable to the HB Lands Royalties as at January 1, 2004.

“Proved” and **“probable”** reserves have the meanings given to those terms under “Disclosure of Reserves Data”.

“Record Date” means the last day of each calendar month.

“Replacement Properties” means properties, whether Additional Royalties or Additional Properties, which were acquired by the Trust and/or Freehold Resources by means of an exchange of properties owned by the Trust or Freehold Resources or using funds obtained through the prior sale of HB Lands Royalties and/or Freehold Resources Properties.

“Reserve Life Index” is an index reflecting the theoretical production life of a property if the remaining reserves were to be produced out at current rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the estimated production for the following 12 month period.

“Rife” means Rife Resources Ltd.

“Royalty Income” means income to the Trust from the HB Lands Royalties, Additional Royalties and the Freehold Resources Royalty.

“Royalty Interest” means the percentage of the gross proceeds from the sale of the produced substances, or that same percentage of the produced substances delivered in-kind to the royalty owner as may be provided for by the lease agreement between the royalty owner(s) and the lessee(s).

“Royalty Lands” means the lands from which the HB Lands Royalties and the Additional Royalties are derived.

“Royalty Lands Royalty Income” means the income derived from the HB Lands Royalties and the Additional Royalties.

“Royalty Sale Agreement” means the purchase and sale agreement between Canpar and the Trust which provided for the purchase by the Trust from Canpar of the HB Lands Royalties.

“Share Trust” means the trust established by agreement dated September 30, 1996 which holds the 100 issued and outstanding common shares in the capital of Freehold Resources, the beneficiaries of which trust are the Manager as to 20 shares, and the independent directors of Freehold Resources from time to time, as to 80 shares.

“Special Resolution” means a resolution passed by a majority of not less than 66 2/3% of the votes cast, either in person or by proxy, at a meeting of Unitholders, called for the purpose of approving such resolution, or approved in writing by the holders of not less than 66 2/3% of the Trust Units entitled to be voted on such resolution.

“Tax Act” means the Income Tax Act (Canada) and the regulations thereunder.

“Trimble” means Trimble Engineering Associates Ltd., independent qualified reserves evaluators.

“Trimble Report” means the report dated January 30, 2004 prepared by Trimble, evaluating the oil, natural gas, natural gas liquids and sulphur reserves attributable to the Royalty Interest properties and the Freehold Resources Properties as at December 31, 2003.

“Trust” means Freehold Royalty Trust.

“Trustee” means Computershare Trust Company of Canada.

“Trust Indenture” means the amended and restated trust indenture dated May 1, 2002 between the Trustee and Freehold Resources as amended from time to time.

“Trust Units” means the units of the Trust, each unit representing an equal undivided beneficial interest therein.

“Unanimous Shareholder Agreement” means the agreement dated November 25, 1996 among Freehold Resources, the trustee of the Share Trust and the Trustee for and on behalf of Unitholders.

“Unitholders” means holders of Trust Units of the Trust.

“Working Interest Properties” means the properties and assets acquired by Freehold Resources from each of Canpar and Rife pursuant to the Working Interest Sale Agreements, and additional working interests acquired.

“Working Interest Sale Agreements” means the purchase and sale agreement between Freehold Resources and Rife and the purchase and sale agreement between Freehold Resources and Canpar which provided for the purchase by Freehold Resources from Rife and Canpar of the Working Interest Properties.

ABBREVIATIONS

bbl and bbls	barrel and barrels, respectively, each barrel representing 34.972 Imperial gallons or 42 U.S. gallons	mboe	one thousand barrels of oil equivalent
bbls/d and bopd	barrels per day and barrels of oil per day, respectively	mmboe	one million barrels of oil equivalent
mbbls	one thousand barrels	mcf	one thousand cubic feet
mmbbls	one million barrels	mcf/d	one thousand cubic feet per day
boe	barrels of oil equivalent converting 6 mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert natural gas and natural gas liquids to oil equivalent is not based on either energy content or prices but on a commonly used industry benchmark. Sulphur volumes are not included.	mmcf	one million cubic feet
boe/d	barrels of oil equivalent per day	mmbtu	one million British Thermal Units
		mtonne	one thousand tonnes
		AECO	reference pricing point for natural gas located at a natural gas storage facility near the Alberta - Saskatchewan border
		API	American Petroleum Institute
		NGLs	natural gas liquids
		WTI	West Texas Intermediate

CONVERSIONS

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.471

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

CORPORATE STRUCTURE

Freehold Royalty Trust

Freehold Royalty Trust (the "Trust") was a closed-end investment trust created under the laws of the Province of Alberta pursuant to the Trust Indenture dated September 30, 1996 as amended and restated November 25, 1996 until its conversion to an open-end trust pursuant to an amended and restated Trust Indenture dated effective May 4, 1999. Computershare Trust Company of Canada (the "Trustee") has been appointed as trustee pursuant to an amended and restated Trust Indenture dated effective May 1, 2002. The Trust was created for the purposes of purchasing the HB Lands Royalties from Canpar Holdings Ltd. ("Canpar") and the Freehold Resources Royalty from Freehold Resources Ltd. ("Freehold Resources") and issuing Trust Units to the public. The beneficiaries of the Trust are holders of the Trust Units. The principal and head office of the Trust is located at Suite 400, 144 – 4th Avenue S.W., Calgary, Alberta, T2P 3N4.

Freehold Resources Ltd.

Freehold Resources Ltd. ("Freehold Resources") was incorporated under the Business Corporations Act (Alberta) on June 3, 1996 as 698108 Alberta Ltd., then changed its name to "Freehold Resources Ltd." on July 24, 1996. All of the issued and outstanding shares of Freehold Resources are held by the Share Trust, the beneficiaries of which are the Manager, as to 20 shares, and the independent directors of Freehold Resources from time to time, as to 80 shares. The business of Freehold Resources is restricted to the acquisition, development, exploitation and disposition of oil and natural gas properties, including the Working Interest Properties, and the granting of the Freehold Resources Royalty to the Trust. The head, principal and registered office of Freehold Resources is located at Suite 400, 144 – 4th Avenue S.W., Calgary, Alberta, T2P 3N4.

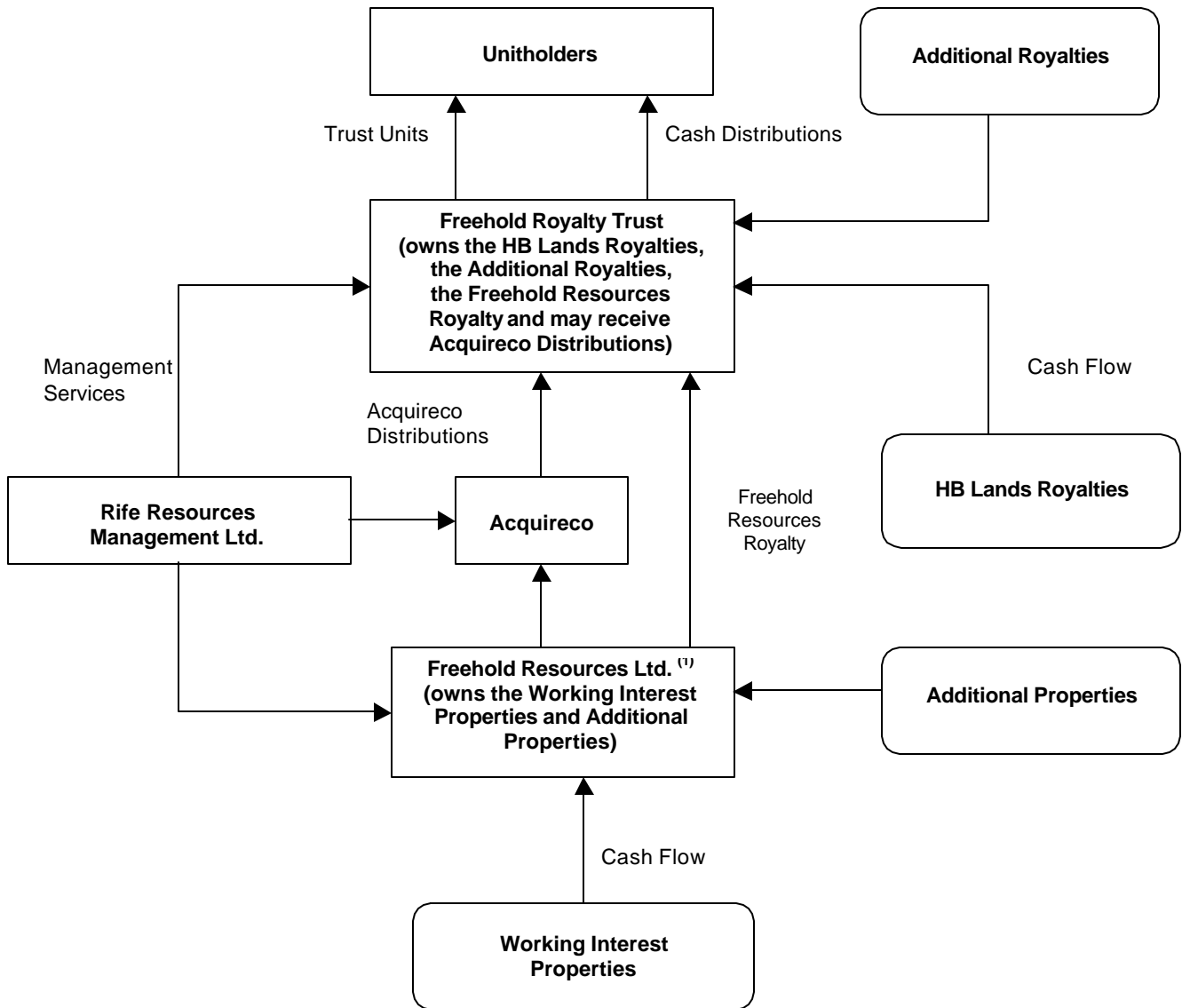
Rife Resources Management Ltd.

Rife Resources Management Ltd. (the "Manager") was incorporated under the Corporations Act (Ontario) on March 5, 1968 under the name "75-89 Gosford Limited" and continued under the Canada Business Corporations Act on April 20, 1979. The Manager changed its name to "Rife Resources Management Ltd." on October 1, 1996. Pursuant to the Management Agreement the Trust has retained the Manager to administer the Trust on behalf of the Trustee and Freehold Resources has retained the Manager for the purposes of identifying, evaluating and assisting in the acquisition, disposition and ongoing management and administering of the HB Lands Royalties, Additional Royalties, the Freehold Resources Royalty and the Freehold Resources Properties. The head, principal and registered office of the Manager is located at Suite 400, 144 – 4th Avenue S.W., Calgary, Alberta, T2P 3N4.

Structure of the Trust

The structure of the Trust is such that income taxation occurs only in the hands of the Unitholder. Distributions to Unitholders consist essentially of the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty received by the Trust together with any interest or other income earned by the Trust from Permitted Investments and any ARC received by the Trust less the direct expenses of the Trust. Freehold Resources determines the Freehold Resources Royalty for each calendar month and arranges for payment of all direct expenses of the Trust from the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty. To the extent that the Trust receives Acquireco Distributions, the Trust will make cash distributions of such funds, subject to required deductions, to Unitholders.

The structure of the Trust and the flows of cash from the HB Lands Royalties, the Additional Royalties, the Working Interest Properties, the Freehold Resources Royalty and Acquireco Distributions to Unitholders is set forth below:



Note:

(1) Owned by the Share Trust.

GENERAL DEVELOPMENT OF THE BUSINESS

Freehold Resources and the Trust were created by the Manager for purposes of purchasing and managing the HB Lands Royalties, the Freehold Resources Royalty and the Working Interest Properties, which were acquired in November 1996.

History and Development

The following is a description of the general development of the business of the Trust over its last three completed financial years.

Year Ended December 31, 2003

In 2003, the Trust purchased an additional royalty interest in the Elswick Midale Beds Voluntary Unit #2 in Southeast Saskatchewan, a 12% royalty interest in 4 natural gas wells in Cecilia, Alberta and a 7.5% working interest in a natural gas well in Woodriver, Alberta. In the Loon area of Northern Alberta, the Trust swapped its working interest holdings for a royalty interest in 28 producing oil wells. The purchase price for these interests was \$3.4 million in aggregate. Combined, these properties will add approximately 100 boe/d to the Trust's production base in 2004.

Year Ended December 31, 2002

The Trust acquired two royalty properties and completed one property swap for \$2.3 million (net of adjustments) in the last half of 2002. At Lashburn, Saskatchewan, the Trust purchased a 6% gross overriding royalty interest in the north half of Section 18-49-23 W3. In the Southeast Saskatchewan area, the Trust acquired a variety of minor title interests in 960 acres of land producing medium to light gravity oil. In the Enchant area of Southern Alberta, the Trust swapped its working interest holdings for a 4.4% gross overriding royalty interest in 2,760 acres.

Year Ended December 31, 2001

On April 30, 2001, the Trust completed the acquisition of producing royalty properties and an interest in approximately 95,000 gross acres of undeveloped mineral title and gross overriding royalty lands in Southeast Saskatchewan. The properties were acquired by Rife on behalf of the Trust. The adjustment date for revenue and cost adjustment purposes for the acquisition was January 1, 2001. The purchase price, net of closing adjustments, was \$25.4 million and was initially financed through the Trust's credit facility.

On May 17, 2001, the Trust issued 3.3 million Trust Units at a price of \$9.65 per Trust Unit for gross proceeds of \$31.8 million (\$30.5 million net of issuance costs). The net proceeds were used to reduce debt.

On November 1, 2001, the Trust acquired approximately 140 boe/d of royalty production in the Hayter property and 20 boe/d of miscellaneous royalty and working interest production in proximal properties for \$4.3 million. The properties were acquired by Rife on behalf of the Trust. The acquisition was funded through the Trust's existing credit facility.

BUSINESS OF THE TRUST

Overview

The Trust was created for the purposes of purchasing the HB Lands Royalties from Canpar, purchasing the Freehold Resources Royalty from Freehold Resources and issuing Trust Units to the public. The Trust permits investors to participate in the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty derived from the Working Interest Properties. Pursuant to the Deferred Purchase Price Obligation, Unitholders also participate in a royalty of 99% of royalty income derived from any Additional Properties and Replacement Properties which Freehold Resources acquires. As a result of the conversion to an open-end trust, Unitholders may also participate in distributions received by the Trust from Acquireco, if any.

The Trust's current assets consist of Permitted Investments, the HB Lands Royalties, Additional Royalties and the Freehold Resources Royalty. The Freehold Resources Royalty consists of 99% of the Freehold Resources Royalty Income. To date no additional assets have been acquired by the Trust through Acquireco.

New Acquisitions Through Acquireco

As a result of the conversion to an open-ended trust on May 4, 1999, the business of the Trust was expanded to include the ability to acquire and hold all forms of petroleum and natural gas related assets that can be reasonably expected to provide long-term returns and Unitholder distributions. As a result, the Trust is now able to form one or more corporations, which would initially be wholly-owned subsidiaries of the Trust (each such company referred to as "Acquireco"), through which future acquisitions of all forms of petroleum and natural gas related assets (for example, the shares of an oil and gas company or petroleum and natural gas related facilities without associated properties) could be effected. To date no such corporation has been organized. Any such corporation would be organized substantially along the lines of Freehold Resources in terms of its relationship with management, the Trust and the Unitholders with the same directors as the board of directors of Freehold Resources.

Upon Acquireco closing any acquisition, Acquireco (or, if merged with Freehold Resources, the merged corporation) will receive cash flow from the operation and ownership of its assets. With the approval of its board of directors and subject to applicable law, Acquireco will distribute to the Trust all of its available cash flow, less certain deductions, including, without limitation, ongoing capital expenditures to the extent not funded by debt and subject to retaining such reasonable reserves or funds for the acquisition of replacement assets as may be considered appropriate by its board of directors ("Acquireco Distributions").

The Trust will make cash distributions of such funds, subject only to required deductions and other deductions similar in nature to those made in respect of the Trust's cash distributions of funds paid to it by Freehold Resources. Such cash distributions may be wholly or in part taxable. In approving any future acquisitions, the board of directors will be required to consider the impact that such acquisition would have on anticipated after-tax Distributions to Unitholders.

Management Policies and Acquisition Strategy

The Manager manages the Trust and Freehold Resources in accordance with the Management Agreement. All activities undertaken by the Manager are directed towards maximizing Distributions to Unitholders while at the same time striving to acquire appropriate assets to provide for long-term growth in the value of the Trust. These two objectives are fundamental to the operation of the Trust and are pursued to maximize value to the Unitholders.

The Manager utilizes its contract staff's extensive experience and employs prudent oil and gas business practices to increase the assets of the Trust through the acquisition of both royalty and working interest producing oil and natural gas properties.

The Trust may acquire Additional Royalties and may acquire all forms of petroleum and natural gas related assets through Acquireco. Freehold Resources may acquire Additional Properties or participate in development activities on Working Interest Properties that are of a low risk nature and that have long-term value enhancement potential. Properties to be acquired may be operated by competent third parties or may require the Manager to assume operatorship on behalf of Freehold Resources.

The Manager's acquisition strategy will target individual properties, or groups of properties, that generally comply with the following criteria and procedures:

- (i) quality producing properties with an established production history and low reserve risk;
- (ii) on the basis of a technical and economic engineering evaluation, a property, or group of properties, acquired in a single transaction which is forecast to provide an internal rate of return that is greater than 400 basis points above long-term (10 year) Government of Canada bonds after deducting General and Administrative Costs and incorporating the impact of debt financing, but before income taxes;
- (iii) commodity price and exchange rate assumptions used in acquisition evaluations will be from an independent engineering firm acceptable to the board of directors of Freehold Resources as recommended by the Manager;
- (iv) each acquisition of a property, or group of properties, for a purchase price of \$5 million or more, will be based on a technical and economic valuation in a report prepared by an independent engineering firm, which, with the acceptance of the board of directors of Freehold Resources, may be modified to incorporate the technical views of the Manager;
- (v) properties which have high netbacks;

- (vi) properties having strong third party operators or properties where the Manager can assume operatorship;
- (vii) the expected economic life of a property, or group of properties, acquired in a single transaction will not be less than 10 years.
- (viii) no acquired property which is comprised of an interest in a single oil or natural gas pool shall represent more than 30% of the Asset Value of the Trust and Freehold Resources; and
- (ix) the Trust may acquire Additional Royalties, of the nature of the HB Lands Royalties, from Canpar or others. The criteria for acquisition of such royalties may be varied from the criteria set out herein, with the approval of a majority of the independent members of the board of directors of Freehold Resources, in recognition of the unique economic characteristics of such royalties.

These criteria will serve as guidelines for the Manager on presenting acquisitions for approval by the board of directors of Freehold Resources. The board of directors of Freehold Resources may vary these criteria for any particular acquisition based on the Manager's recommendations and consideration of the qualitative aspects of the subject properties including risk profile, technical upside, Reserve Life Index and asset quality.

Employees

The Trust has no employees but rather is managed by the Manager pursuant to the Management Agreement. At December 31, 2003, the Manager had 65 full and part-time employees. These personnel also render services to Canpar and Rife.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 30, 2004. The effective date of the Statement is December 31, 2003 and the preparation date of the Statement is February 19, 2004.

Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by independent qualified reserves evaluator, Trimble Engineering Associates Ltd. ("Trimble"), with an effective date of December 31, 2003 contained in the Trimble Report. The Reserves Data summarizes the oil, natural gas liquids and natural gas reserves of the Trust and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Trimble Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Trust engaged Trimble to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Trust's reserves are in Canada and, specifically, in the provinces of Manitoba, Saskatchewan, Alberta and British Columbia.

In order to provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). The Trust uses a conversion rate of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant prices and costs assumptions and forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Trust's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Constant Prices and Costs

SUMMARY OF OIL AND GAS RESERVES as at December 31, 2003 CONSTANT PRICES AND COSTS

Reserves Category	Reserves ⁽¹⁾							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross (mmbbls)	Net (mmbbls)	Gross (mmbbls)	Net (mmbbls)	Gross (mmcf)	Net (mmcf)	Gross (mmbbls)	Net (mmbbls)
Proved								
Developed producing	2,538	4,707	1,375	4,868	6,598	27,299	356	1,009
Developed non-producing	-	-	-	-	266	216	1	1
Undeveloped	-	12	210	266	6	8	1	1
Total proved	2,538	4,719	1,585	5,134	6,870	27,523	358	1,011
Probable	597	1,503	1,323	3,000	2,062	10,957	79	293
Total proved plus probable	3,135	6,222	2,908	8,134	8,933	38,480	437	1,304

Note:

- (1) The Trust is somewhat unique in that the majority of its assets are royalty interests. Under NI 51-101 the definition of Gross reserves excludes royalty interests. This results in the anomaly of the Trust's Gross reserves being lower than Net reserves.

NET PRESENT VALUES OF FUTURE NET REVENUE as at December 31, 2003 CONSTANT PRICES AND COSTS

Reserves Category	Before Income Taxes (\$000s) Discounted at (%/year)				
	0%	5%	10%	15%	20%
Proved					
Developed producing	423,534	287,739	223,308	185,247	159,809
Developed non-producing	1,390	1,139	962	834	737
Undeveloped	3,752	2,888	2,311	1,900	1,596
Total proved	428,676	291,766	226,581	187,981	162,142
Probable	163,331	86,500	56,151	40,557	31,186
Total proved plus probable	592,007	378,266	282,732	228,538	193,328

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) as of December 31, 2003 CONSTANT PRICES AND COSTS

(\$000s)	Reserves Category	
	Proved	Proved Plus Probable
Revenue from Working Interest Properties	183,505	251,757
Royalty income	317,233	452,841
Royalty expense on Working Interest Properties	(15,337)	(22,809)
Operating costs	(53,193)	(75,741)
Development costs	(1,899)	(12,308)
Well abandonment costs	(3,402)	(3,968)
Alberta Royalty Credits	1,770	2,236
Future net revenue before income taxes	428,677	592,007

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2003
CONSTANT PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes Discounted at 10%/year (\$000s)
Proved	Light and Medium Oil (including solution gas and other by-products)	80,505
	Heavy Oil (including solution gas and other by-products)	66,332
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	79,743
Proved plus probable	Light and Medium Oil (including solution gas and other by-products)	97,457
	Heavy Oil (including solution gas and other by-products)	86,839
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	98,435

Forecast Prices and Costs

SUMMARY OF OIL AND GAS RESERVES
as at December 31, 2003
FORECAST PRICES AND COSTS

Reserves Category	Reserves ⁽¹⁾							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross (mbbls)	Net (mbbls)	Gross (mbbls)	Net (mbbls)	Gross (mmcf)	Net (mmcf)	Gross (mbbls)	Net (mbbls)
Proved								
Developed producing	2,536	4,717	1,350	4,848	6,563	27,275	355	1,009
Developed non-producing	-	-	-	-	267	216	1	1
Undeveloped	-	12	210	266	6	8	1	1
Total proved	2,536	4,729	1,560	5,114	6,836	27,499	358	1,011
Probable	596	1,505	1,313	2,993	2,052	10,950	78	293
Total proved plus probable	3,132	6,234	2,873	8,107	8,888	38,499	436	1,304

Note:

- (1) The Trust is somewhat unique in that the majority of its assets are royalty interests. Under NI 51-101 the definition of Gross reserves excludes royalty interests. This results in the anomaly of the Trust's Gross reserves being lower than Net reserves.

NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2003
FORECAST PRICES AND COSTS

Reserves Category	Before Income Taxes (\$000s) Discounted at (%/year)				
	0%	5%	10%	15%	20%
Proved					
Developed producing	406,803	264,713	202,359	167,133	144,172
Developed non-producing	1,227	1,009	856	745	661
Undeveloped	3,276	2,481	1,958	1,590	1,320
Total proved	411,306	268,203	205,173	169,468	146,153
Probable	169,325	81,909	50,618	35,531	26,819
Total proved plus probable	580,630	350,112	255,791	204,999	172,972

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2003
FORECAST PRICES AND COSTS

(\$000s)	Reserves Category	
	Proved	Proved Plus Probable
Revenue from Working Interest Properties	189,510	256,502
Royalty income	306,128	454,232
Royalty expense on Working Interest Properties	(13,486)	(20,125)
Operating costs	(65,948)	(94,001)
Development costs	(1,946)	(12,482)
Well abandonment costs	(4,741)	(5,757)
Alberta Royalty Credits	1,789	2,260
Future net revenue before income taxes	411,306	580,630

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2003
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes Discounted at 10%/year (\$000s)
Proved	Light and Medium Oil (including solution gas and other by-products)	73,492
	Heavy Oil (including solution gas and other by-products)	61,196
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	70,484
Proved plus probable	Light and Medium Oil (including solution gas and other by-products)	88,737
	Heavy Oil (including solution gas and other by-products)	79,819
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	87,235

Definitions and Other Notes:

- Columns may not add due to rounding.
- The oil, natural gas liquids and natural gas reserve estimates presented in the Trimble Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions.

Reserves are classified according to the degree of certainty associated with the estimates.

- Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook. Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
 - (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
 - (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Constant Prices and Costs

Constant prices and costs are:

- (a) the forecast prices and costs as at January 1, 2004, held constant throughout the estimated lives of the properties to which the estimate applies; and
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Trust is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), the Trust's prices are the forecast 2004 prices for oil, natural gas and natural gas liquids after historical adjustments for transportation, gravity and other factors.

The constant oil and natural gas benchmark reference pricing and the exchange rate utilized in the Trimble Report were as follows:

CONSTANT PRICES USED IN ESTIMATES
as of January 1, 2004

OIL				NATURAL GAS	NATURAL GAS LIQUIDS FOB Field Gate (\$Cdn/bbl)			EXCHANGE RATE
WTI Cushing Oklahoma \$US/bbl	Edmonton Par Price 40° API \$Cdn/bbl	Hardisty Heavy 12° API \$Cdn/bbl	Hardisty Bow River 24.9° API \$Cdn/bbl	AECO 30 Day Spot (\$Cdn/mmbtu)	Propane	Butane	Pentane	\$ US/\$ Cdn
29.63	37.99	23.80	29.69	6.04	28.04	31.15	38.91	0.75

4. Forecast Prices and Costs

Forecast prices and costs are those:

- (a) generally acceptable as being a reasonable outlook of the future; and
- (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Trust is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Oil and natural gas benchmark reference pricing, inflation and exchange rates as at January 1, 2004 utilized in the Trimble Report were as follows:

FORECAST PRICES USED IN ESTIMATES
as at January 1, 2004

YEAR	OIL				NATURAL GAS	NATURAL GAS LIQUIDS FOB Field Gate (\$Cdn/bbl)			Inflation Rate	Exchange Rate
	WTI Cushing Oklahoma \$US/bbl	Edmonton Par Price 40° API \$Cdn/bbl	Hardisty Heavy 12° API \$Cdn/bbl	Hardisty Bow River 24.9° API \$Cdn/bbl	AECO 30 Day Spot (\$Cdn/mmbtu)	Propane	Butane	Pentane	%/year	\$U.S./\$Cdn
Forecast										
2004	29.63	37.99	23.80	29.69	6.04	28.04	31.15	38.91	1.5	0.75
2005	26.80	34.24	21.28	26.64	5.36	22.56	25.52	35.07	1.5	0.75
2006	25.76	32.87	20.80	25.72	4.80	20.58	23.28	33.67	1.5	0.75
2007	26.14	33.37	21.33	26.27	4.91	20.89	23.63	34.17	1.5	0.75
2008	26.53	33.87	21.84	26.74	4.98	21.20	23.98	34.69	1.5	0.75
Thereafter, per year	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	1.5	0.75

FREEHOLD WEIGHTED AVERAGE PRICES
Year ended December 31, 2003

	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids
	(\$/bbl)	(\$/bbl)	(\$/mcf)	(\$/bbl)
Freehold weighted average price	38.98	28.00	6.18	30.95

5. The Trust is a mutual fund trust under the Tax Act and distributes all of its taxable income to the Unitholders. By doing so, exposure to current tax at the trust level is eliminated. In addition, the Trust is exempt from future income taxes because it is contractually committed to distribute all of its income to Unitholders.
6. "Development well" means a well drilled inside the established limits of an oil and natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
7. "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
 - (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, natural gas lines and power lines, pumping equipment and wellhead assembly;
 - (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
 - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
 - (d) provide improved recovery systems.
8. "Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply injection, observation or injection for combustion.
9. Future Development Costs

The following table sets forth development costs deducted in the estimation of the Trust's future net revenue attributable to the reserve categories noted below.

Year	Forecast Prices and Costs		Constant Prices and Costs
	Proved Reserves (\$000s)	Proved Plus Probable Reserves (\$000s)	Proved Reserves (\$000s)
2004	1,164	4,818	1,164
2005	117	3,603	117
2006	119	2,106	117
2007	121	1,414	117
2008	61	61	58
Remainder	362	478	324
Total Undiscounted	1,946	12,482	1,899
Total Discounted at 10%	1,600	10,626	1,577

The source of funding for future development costs will be 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.

10. ARC is included in the cumulative cash flow amounts.
11. Estimated future well abandonment costs have been taken into account by Trimble in determining reserves and the aggregate future net revenue. No allowance was made, however, for reclamation of wellsites or the abandonment and reclamation of any facilities.
12. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.
13. The extent and character of all factual data supplied to Trimble were accepted by Trimble as represented. No field inspection was conducted.

Certain other terms used herein but not defined herein are defined in NI-51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI-51-101.

Reconciliation of Changes in Reserves and Future Net Revenue

RECONCILIATION OF COMPANY NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

Factors	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable
	(mbbls)	(mbbls)	(mbbls)	(mbbls)	(mbbls)	(mbbls)	(mmcf)	(mmcf)	(mmcf)
December 31, 2002 ⁽¹⁾	6,213	1,008	7,221	6,915	1,884	8,799	37,107	7,341	44,449
Extensions	26	9	35	-	-	-	-	-	1
Improved recovery	-	5	5	-	-	-	-	-	-
Technical revisions	(1,266)	239	(1,027)	(1,070)	986	(84)	(6,961)	2,859	(4,102)
Discoveries	213	194	407	114	129	242	766	507	1,272
Acquisitions	70	51	121	-	-	-	233	273	506
Dispositions	(46)	-	(46)	-	-	-	-	-	-
Economic factors	6	2	8	(9)	(6)	(15)	(43)	(14)	(57)
Production	(487)	(3)	(490)	(836)	-	(836)	(3,603)	(15)	(3,619)
December 31, 2003	4,729	1,505	6,233	5,114	2,993	8,106	27,499	10,950	38,450

Note:

- (1) The evaluation as at December 31, 2002 was prepared by Trimble using National Policy 2-B reserves definitions. Under those definitions, probable reserves were adjusted by a factor to account for the risk associated with their recovery. The Trust previously applied a risk factor of 50% in reporting probable reserves. Under current NI 51-101 reserves definitions, estimates are prepared such that the full proved plus probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "best estimate"). The above reconciliation reflects current probable reserves versus previous risk adjusted (50%) probable reserves reported by the Trust.

RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF
FUTURE NET REVENUE OF PROVED RESERVES BEFORE TAX
DISCOUNTED AT 10% PER YEAR
CONSTANT PRICES AND COSTS

For the year ended December 31, 2003	(\$000s)
Estimated future net revenue at beginning of year	276,279
Sales and transfers of oil and natural gas produced, net of production costs and royalties	(57,582)
Net change in prices, production costs and royalties related to future production	(2,896)
Changes in previously estimated development costs incurred during the year	(1,230)
Changes in estimated future development costs	-
Extensions and improved recovery	477
Discoveries	13,463
Acquisitions of reserves	3,141
Dispositions of reserves	(503)
Net change resulting from revisions in quantity estimates	(32,197)
Accretion of discount	27,629
Estimated future net revenue at end of year	226,581

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards in the COGE Handbook. In general, undeveloped reserves are scheduled to be developed within the next two years. Capital expenditures to develop proved undeveloped reserves are estimated at \$1.2 million in 2004 and \$0.1 million in 2005.

Almost all of the proved undeveloped reserves assigned in the Trimble Report are in the Hayter, Alberta property. Ten infill wells are scheduled to be drilled in 2004.

The majority of the probable undeveloped reserves in the Trimble Report are also in the Hayter, Alberta property. Ten wells a year are forecast to be drilled in 2005, 2006 and 2007.

Significant Factors or Uncertainties

The reserve and recovery information contained in the Trimble Report are only estimates and the actual production and ultimate reserves may be greater or less than the estimates prepared by Trimble.

The value of the Trust Units will depend upon, among other things, the reserves attributable to the Trust's properties. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the Trust's properties will vary from estimates and those variations could be material. The reserve and cash flow information contained in this Statement represents estimates only. Reserves and estimated future net cash flow from the Trust's properties have been evaluated by an independent qualified reserves evaluator. This firm considers a number of factors and makes assumptions when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices; production and development costs, severance and excise taxes, and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- timing and amount of capital expenditures;
- marketability of production;
- future prices of oil and natural gas;
- operating costs and royalties; and
- other government levies that may be imposed over the producing life of reserves.

These factors and assumptions were based on prices at the date the evaluation was prepared. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve estimates. Many of

these factors are subject to change and are beyond the Trust's control. For example, the evaluation is based in part on the assumed success of exploitation activities intended to be undertaken in future years. Actual reserves and estimated cash flows will be less than those contained in the evaluation to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation. Furthermore, cash flows may differ from those contained in the evaluation depending upon whether capital expenditures and operating costs differ from those estimated in the evaluation.

DESCRIPTION OF PROPERTIES

In the following discussion, all references to reserves are Net, utilizing escalated price and cost assumptions, before tax. Unless stated otherwise, reserve values are proved plus probable.

Royalty Lands

HB Lands Royalties

The HB Lands Royalties are derived from the leased mineral title lands and royalty assumption lands acquired by the Trust from Canpar which generated production revenue in 1995. Canpar retained all non-producing deeper rights associated with the HB Lands. The Trust's interest in leased mineral titles lands and royalty assumption lands, in addition to oil and natural gas, also includes most other minerals excluding coal. The Trust also derives income from the mining of potash. See "Potash Interests and Reserves".

Additional Royalties

Since inception, the Trust has acquired Additional Royalties from properties located near Swift Current, Luseland, Lashburn and Southeast Saskatchewan; and Cecilia, Loon, Hayter, Wildmere, Giltedge and Enchant, Alberta. This category provided approximately 28% of the Royalty Lands Royalty Income received by the Trust in 2003.

Royalty Lands Royalty Income

The Royalty Lands are comprised of a large and widely diversified portfolio of properties extending from northeast British Columbia to southwest Manitoba, which have been divided into seven areas. The single largest royalty from an individual lease acquired by the Trust on the Royalty Lands accounted for less than 4% of the total revenue attributable to the Royalty Lands Royalty Income in 2003. The majority of Royalty Lands Royalty Income is derived from the central area of southern Alberta and southern Saskatchewan.

Royalty Lands Summary

The following is a summary of information pertaining to the Royalty Lands, including the HB Lands Royalties and Additional Royalties on a combined basis.

The Trust's royalty reserves are derived from (i) mineral title lands which are owned by the Trust and upon which the Trust is paid lessor royalties (approximately 75% of royalty revenue); (ii) royalty assumption lands owned by third parties and which by their terms, are expressed to be interests in land (approximately 11% of royalty revenue); and (iii) reserves owned by third parties upon which such third parties pay royalties or net profits interests to the Trust, which may or may not be interests in land (approximately 14% of royalty revenue).

Mineral Title Lands

This category of land provided approximately 75% of the royalty income received by the Trust in 2003. This royalty income is derived from the royalties payable to the Trust through the lease documents issued to the companies, which have producing wells located thereon. The Trust has ownership interests in mineral titles ranging from 10% to 100% and recovers a similar percentage of the applicable royalty, ranging from 10% to 20% of all oil and natural gas products produced and sold from the leased lands. For example if the Trust's interest in a mineral title property is 50% and the royalty rate applicable to the lease is 20% then the Trust would be entitled to receive the proceeds from the sale of 10% (50% x 20%) of the oil or natural gas produced for the period. The area of leased mineral title lands totals approximately 482,100 gross acres. Certain of the leased mineral title lands have over time been included within 176 oil and natural gas production units which ensure royalty payments to the Trust over the entire producing life of the unit. The leased mineral title lands also include approximately 144,600 gross undeveloped acres, representing potential for further development of the leased mineral title lands.

Royalty Assumption Lands

These lands consist of 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 the Trust. Certain of the gross overriding royalty interests have been included in 28 oil and natural gas production units. This category of land provided approximately 11% of the royalty income received by the Trust in 2003. The Trust holds a royalty interest in 96,402 acres, of which approximately 17,700 acres are undeveloped.

Gross Overriding Royalty Lands

These lands consist of properties owned by a number of third party oil and gas companies in respect of which varying gross overriding royalties have been reserved to the Trust. This category of land provided approximately 14% of the royalty income received by the Trust in 2003. Certain of the gross overriding royalty interests have been included within 67 oil and natural gas production units. The Trust holds a royalty interest in 228,504 acres, of which approximately 38,300 acres are undeveloped.

The following table summarizes by area the Trust's average interest, 2003 wells drilled, 2003 oil and natural gas production, Net reserves, 2003 net pre-tax cash flow and reserve value for the Trust's Royalty Lands:

Royalty Lands	Average Royalty Interest (%)	2003 Wells Drilled (gross)	2003 Production (boe/d)	Net Reserves (mboe)	2003 Net Pre-Tax Cash Flow (\$000s)	Reserve Value Discounted at 10%/year (\$000s) (%)	
Western Alberta	0.5	22	813	3,637	10,998	47,900	23.9
Bashaw/Leduc	0.7	39	329	1,052	4,569	17,158	8.6
Northeast Alberta	2.0	58	602	2,784	6,830	32,946	16.5
Saskatchewan Heavy Oil	6.0	49	782	2,184	8,225	27,026	13.5
Southeast Alberta	0.9	253	446	1,513	5,250	21,403	10.7
Hatton/Gull Lake	0.8	73	185	1,115	2,264	13,638	6.8
Southeast Saskatchewan	0.7	74	669	1,576	9,382	26,331	13.2
Other	0.5	8	146	865	2,332	13,715	6.8
TOTAL	0.8	576	3,972	14,726	49,850	200,117	100.0

The following table summarizes the oil and natural gas gross acreage, gross wells and production unit interests owned by the Trust in the core areas of the Royalty Lands:

Area	Total Acres	Undeveloped Acres ⁽¹⁾	Non-Unitized		Unitized		
			Natural Gas Wells	Oil Wells	Production Units	Natural Gas Wells	Oil Wells
Western Alberta	93,658	15,930	79	129	64	388	1,840
Bashaw/Leduc	66,300	7,149	107	111	38	452	638
Northeast Alberta	123,917	18,816	181	512	32	508	803
Saskatchewan Heavy Oil	62,764	14,403	46	499	6	31	438
Southeast Alberta	128,891	11,591	729	147	46	3,100	275
Hatton/Gull Lake	124,898	25,264	351	195	36	7	896
Southeast Saskatchewan	129,931	99,198	2	419	34	-	2,132
Other	76,660	8,298	79	87	15	246	166
TOTAL	807,019	200,649	1,574	2,099	271	4,732	7,188

Note:

- (1) Undeveloped lands are non-producing spacing units on the Royalty Lands.

Western Alberta

In the Western Alberta area, the Trust has interests in the revenue from 93,658 gross acres, which currently includes an interest in 79 non-unitized natural gas wells and 129 non-unitized oil wells and approximately 15,900 gross acres of undeveloped lands. The Trust also owns interests in 64 production units currently containing 388 natural gas wells and 1,840 oil wells. The Trimble Report has assigned reserves of 1,694 mbbbls of oil and NGLs and 11,662 mmcf of natural gas to this royalty interest. Geologically, the Western Alberta area represents a wide distribution of producing fields from the foothills structurally distributed belt at Turner Valley, Jumping Pound West and Wildcat Hills to the northern plains at Whitecourt. Stratigraphically, the properties range from the Devonian Beaver Hill Lake formation in

the Caroline Swan Hills Gas Unit at a depth of 13,000 feet to the shallower Upper Cretaceous Edmonton Group zone in the Pembina and Keystone areas at a depth of less than 2,500 feet. The single largest revenue property is the Caroline Swan Hills Gas Unit #1, which produces most of the Trust's NGLs. The Cardium formation is the most common producing formation in which the Trust has interests, including 24 unitized pools in the Ricinus, Ferrier, Willesden Green and Pembina fields. The oil production from this area is typically of higher degree API quality and the natural gas production may often contain NGLs. Oil and NGL production was stable at 338 bbls/d during 2003 and natural gas production was 16% higher than 2002 at 2,847 mcf/d. During 2003, lessees drilled 22 wells in the area compared to 31 wells in 2002.

Bashaw/Leduc

In the Bashaw/Leduc area, the Trust owns an interest in the revenue from 66,300 gross acres, which includes interests in 107 non-unitized natural gas wells and 111 non-unitized oil wells and approximately 7,100 acres of undeveloped land. The Trust also has interests in 38 production units containing 452 natural gas wells and 638 oil wells. The Trimble Report has assigned reserves of 557 mmbbls of oil and NGLs and 2,972 mmcf of natural gas to this royalty interest. This area encompasses a wide diversity of productive zones from the Devonian Leduc Reef at a depth of 7,500 feet to the Upper Cretaceous Edmonton at less than 1,000 feet. The highest revenue properties in 2003 in this area were the Red Willow Ellerslie natural gas pool, the Leduc-Woodbend Glauconitic D Unit No. 1 and the Halkirk Ellerslie oil pool. Oil and NGL production decreased 4% in 2003 to 150 bbls/d while natural gas production increased 24% to 1,078 mcf/d. Lessees drilled 39 wells in this area during 2003 compared to 56 wells drilled in 2002.

Northeast Alberta

The Northeast Alberta royalty area was created in 2000 by combining the Provost and Lloydminster/Bonnyville areas. Within the Northeast Alberta area, the Trust owns an interest in the revenue from 123,917 gross acres, which includes an interest in 181 non-unitized natural gas wells, 512 non-unitized oil wells and approximately 18,800 acres of undeveloped land. The Trust also has interests in 32 production units currently containing 508 natural gas wells and 803 oil wells. The Trimble Report has assigned reserves of 2,335 mmbbls of oil and NGLs and 2,693 mmcf of natural gas to this royalty interest. The main producing horizons in the Northeast Alberta area are the Viking and Mannville formations. The northern part of the area is characterized by the production of heavier oil and/or natural gas from the shallow (less than 3,300 feet) Mannville sands. In the southern part of the area, the Trust is represented in seven Viking natural gas production units and three Viking oil production units while the Mannville formation produces low to medium gravity oil from multiple sands at depths of less than 3,500 feet. The largest single revenue property is the Hayter Section 26-40-1W4 Dina oil pool. The Wildmere Lloydminster "A" Unit No. 1 is the largest revenue unit. The Trust's 2003 oil and NGL production was down 5% to 475 bbls/d, and natural gas production was down 14% to 763 mcf/d. In this area, 58 wells were drilled during 2003 compared to 38 wells drilled in 2002.

Saskatchewan Heavy Oil

In the Saskatchewan Heavy Oil area, the Trust has an interest in the revenue from 62,764 gross acres, which includes interests in 46 non-unitized natural gas wells and 499 non-unitized oil wells and approximately 14,400 acres of undeveloped land. The Trust also has interests in six production units currently containing 31 natural gas wells and 438 oil wells. The Trimble Report has assigned reserves of 2,074 mmbbls of oil and NGLs and 658 mmcf of natural gas to this royalty interest. The major productive zones are the Mississippian Bakken, the Cretaceous Mannville and the Cretaceous Viking formations. Production of light gravity oil and natural gas from the Viking formation is concentrated in the southern part of the area near Dodsland. Depths of the productive zones range from 2,800 feet in the south to less than 1,000 feet in the north. The Mannville formation is comprised of multiple sands which have the potential to produce heavy oil or natural gas. Significant revenue properties are the Luseland Bakken pool, the Baldwin and Big Gully Sparky pools, and the Carruthers Cumming pool. Oil and NGL production decreased 26% during 2003 to 714 bbls/d, while natural gas production was 23% lower at 411 mcf/d. During 2003, lessees drilled 49 wells compared to 14 in 2002.

Southeast Alberta

The Southeast Alberta area represents the largest number of natural gas wells in which the Trust owns an interest. The Trust has an interest in the revenue from 128,891 gross acres, which includes an interest in 729 non-unitized natural gas wells and 147 non-unitized oil wells and approximately 11,600 acres of undeveloped lands in this area. The Trust also owns interests in 46 production units containing 3,100 natural gas wells and 275 oil wells. These units are predominantly productive from the shallow Upper Cretaceous Milk River, Medicine Hat and Second White Specks zones at depths of less than 2,000 feet. The Trimble Report has assigned reserves of 317 mmbbls of oil and NGLs and 7,172 mmcf of natural gas to this royalty interest. Although shallow gas is the dominant play, oil production from the underlying Mannville Sands also contributes significantly to revenue. Oil and NGL production averaged 150 bbls/d in

2003, up 7% from the previous year. Natural gas production was 52% higher averaging 1,776 mcf/d for the year compared to 1,165 mcf/d in 2002. Approximately 44% of the wells drilled on the Trust's royalty properties during 2003 were drilled in this region. Lessees drilled 253 wells during 2003 compared to 317 wells in 2002.

Hatton/Gull Lake

The Hatton/Gull Lake area of southwestern Saskatchewan has historically provided revenue to the Trust from shallow natural gas production. Following the 1997 acquisition of royalty interests near Swift Current, the Trust now has revenue from oil production. The Trust has an interest in 124,898 gross acres, which includes an interest in 351 non-unitized natural gas wells and 195 non-unitized oil wells and approximately 25,300 acres of undeveloped land. The Trust also has interests in 36 production units containing 7 natural gas wells and 896 oil wells. The Trimble Report has assigned reserves of 2,873 mmcf of natural gas and 636 mbbbls of oil and NGLs to this royalty interest. Oil and NGL production declined 20% to 103 bbls/d in 2003, and natural gas production declined 15% to 495 mcf/d. Lessees drilled a total of 73 wells on these lands in 2003 compared to 72 wells drilled in 2002.

Southeast Saskatchewan

The Southeast Saskatchewan royalty area was created in 2001 following the Trust's acquisition of producing and undeveloped mineral title and gross overriding royalty properties in southeast Saskatchewan. The Trust owns an interest in 129,931 gross acres, which includes an interest in 2 non-unitized natural gas wells, 419 non-unitized oil wells and approximately 99,200 acres of undeveloped land. The Trust also owns an interest in 34 production units containing 2,132 oil wells. The Trimble Report has assigned reserves of 1,523 mmbbls of oil and NGLs and 315 mmcf of natural gas to this royalty interest. Geologically, the Southeast Saskatchewan area is situated on the northern edge of the Williston Basin. Most of the oil is produced from unconformity related traps in the carbonate rocks of the Mississippian aged Madison Group. Light and medium gravity oil is produced from an average depth of approximately 4,000 feet. In the past decade, horizontal wells have become the favored method of exploitation and account for the majority of production. Oil and NGL production increased 14% to 640 bbls/d in 2003 and natural gas production increased 3% to 170 mcf/d. During 2003, 74 wells were drilled by lessees on the acquired lands compared to 69 wells drilled in 2002.

Undeveloped Royalty Lands

The undeveloped lands are non-producing spacing units totaling 200,649 acres approximately one half of which are in the Southeast Saskatchewan area. Potential exists on these lands for drilling non-unitized uphole zones within producing units, drilling or completing additional uphole zones, infill drilling by downsizing the spacing (e.g. 160 acre to 80 acre spacing in the case of an oil well), optimizing drilling locations within spacing units and horizontal drilling. If a well is drilled on lands adjacent to Royalty Lands and that well is producing from a formation in which the Trust has an interest but which is not producing on the Royalty Lands, the Trust has the right to require the lessee of the mineral title to either: (a) drill a well on an undrilled spacing unit on the Royalty Lands; (b) pay a compensatory royalty; or (c) surrender the lease.

Drilling Activity

The Trust is not responsible for any drilling or development activity or expenditures with respect to the Royalty Lands, but receives appropriate royalty income from successful wells. Drilling activity on the Royalty Lands is anticipated to provide continued new sources of oil and natural gas royalty income in future years, with new wells and production thereon reducing the rate at which production and royalty income would otherwise decline. The extent of drilling and development activity in future years by lessees cannot be predicted.

The following table summarizes the drilling activity conducted by lessees on the Royalty Lands for the two most recently completed fiscal years. During this period 1,185 unitized and non-unitized wells were drilled.

Years Ended December 31 (gross wells)	2003		2002	
	Unitized	Non-unitized	Unitized	Non-unitized
Oil wells	105	99	98	95
Natural gas wells	215	100	279	84
Service/other wells	2	44	1	41
Dry and abandoned	-	11	-	11
TOTAL	322	254	378	231
Success rate	100%	96%	100%	95%

The drilling activity on the Royalty Lands in the last two fiscal years may not be indicative of future activity.

Reconciliation of Royalty Lands Reserves

The following table provides a summary of the changes in the Trust's interest in the oil and natural gas reserves on its Royalty Lands which occurred in the period commencing December 31, 2002 and ending December 31, 2003 based on forecast prices and costs:

Factors	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable
	(mmbbls)	(mmbbls)	(mmbbls)	(mmbbls)	(mmbbls)	(mmbbls)	(mmcf)	(mmcf)	(mmcf)
December 31, 2002 ⁽¹⁾	2,920	512	3,432	5,037	1,031	6,067	29,885	5,628	35,513
Extensions	-	-	-	-	-	-	-	-	-
Improved recovery	-	-	-	-	-	-	-	-	-
Technical revisions	(659)	165	(494)	(1,011)	600	(411)	(5,580)	3,019	(2,562)
Discoveries	213	191	404	114	129	242	718	497	1,215
Acquisitions	70	51	121	-	-	-	233	273	506
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Production	(353)	(2)	(354)	(547)	(2)	(550)	(2,914)	(7)	(2,920)
December 31, 2003	2,192	917	3,109	3,592	1,757	5,349	22,342	9,409	31,751

Notes:

- (1) The evaluation as at December 31, 2002 was prepared using National Policy 2-B reserves definitions. Under those definitions, probable reserves were adjusted by a factor to account for the risk associated with their recovery. The Trust previously applied a risk factor of 50% in reporting probable reserves. Under current NI 51-101 reserves definitions, estimates are prepared such that the full proved plus probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "best estimate"). The above reconciliation reflects current probable reserves versus previous risk adjusted (50%) probable reserves reported by the Trust.
- (2) Columns may not add due to rounding.

Freehold Resources Royalty

The Freehold Resources Royalty granted to the Trust pursuant to the Freehold Resources Royalty Agreement consists of a 99% share of the Freehold Resources Royalty Income.

Freehold Resources is required to pay the Trust, on each Cash Distribution Date, 99% of the Freehold Resources Royalty Income received by Freehold Resources from the Freehold Resources Properties for the period ending on the last day of the second month immediately preceding that Cash Distribution Date.

The Trust reimburses Freehold Resources for 99% of the Crown royalties and other Crown charges payable by Freehold Resources in respect of production from or ownership of the Freehold Resources Properties. Freehold Resources will at all times be entitled to set off its right to be so reimbursed against its obligations to pay the Freehold Resources Royalty.

Deferred Purchase Price Obligation

Under the terms of the Freehold Resources Royalty Agreement, the purchase price of the Freehold Resources Royalty acquired by the Trust was an amount equal to 99% of the portion of Freehold Resource's acquisition cost of the Working Interest Properties attributable to "Canadian resource properties", as defined in the Tax Act, (estimated to be 87% of Freehold Resource's total acquisition cost) plus a Deferred Purchase Price Obligation which recognizes that cash flows from Additional Properties and certain capital expenditures will be subject to the Freehold Resources Royalty for the benefit of Unitholders. The Deferred Purchase Price Obligation consists of 99% of the cost of, or any amount borrowed to acquire, a "Canadian resource property", as defined under the Tax Act, subsequently acquired by Freehold Resources and up to 99% of the amount of, or any amount borrowed to incur, certain capital expenditures on the Freehold Resource Properties to the extent so designated by Freehold Resources. Freehold Resources will only designate an amount under the Deferred Purchase Price Obligation in excess of a nominal amount to the extent that the Trust has funds on hand from the issuance of Trust Units or the disposition of HB Lands Royalties or the Freehold Resources Royalty in respect of Freehold Resources Properties which are disposed of. The Trust intends to finance the Deferred Purchase Price Obligations through additional issues of Trust Units or the application of the proceeds of disposition of HB Lands Royalties or Freehold Resources Properties.

Working Interest Properties

Freehold Resources owns interests in 72 Working Interest Properties. Production from these properties is comprised of approximately 75% oil and 25% natural gas. The majority (58%) of the Trust's working interest production comes from 4 properties – Hayter, Pembina Cardium Unit No. 9 and Pouce Coupe South Boundary "B" Unit #2, which are located in Alberta, and Luseland, located in Saskatchewan. Working interest production accounted for 1,845 boe/d in 2003, the same as 2002. In 2003, 74 (6.9 net) wells were drilled on the working interest properties, up 37% from 54 (4.9 net) wells during 2002. Freehold Resources will spend approximately \$4.7 million on development projects during 2004. The majority of this amount is forecast to be spent at Hayter on drilling and related facilities, and to continue the drilling program at Pembina Cardium Unit No. 9. The remaining capital will be spent on miscellaneous properties. Approximately 70% of the present value of the estimated future net cash flow from the Working Interest Properties on which the Freehold Resources Royalty was granted is represented by the Hayter, Pembina Cardium Unit No. 9, Luseland and Pouce Coupe properties as outlined in the table below:

Property	Working Interest ⁽¹⁾	2003 Production	Net Reserves	2003 Net Pre-Tax Cash Flow	Reserve Value ⁽²⁾ Discounted at 10%/year	
	(%)	(boe/d)	(mboe)	(\$000)	(\$000)	(%)
Hayter	23.52	553	2,168	3,403	11,903	21.9
Pembina Cardium Unit No. 9	9.97	306	2,964	3,458	20,962	38.5
Luseland	20.00	115	73	680	694	1.3
Pouce Coupe South Boundary "B" Unit #2	25.56	100	511	851	4,363	8.0
Other (68 properties)	1.92	771	1,611	6,107	16,523	30.3
TOTAL		1,845	7,327	14,498	54,445	100.0

Notes:

(1) The percentage working interest share of reserves and production owned by Freehold Resources in the properties before the deduction of royalties payable to others

(2) Does not include \$1.2 million of ARC.

Hayter, Alberta

Freehold Resources owns a 23.52% working interest in the Hayter property located in east central Alberta. Historically, Freehold Resources owned 23.52% working interest in only Section 26-40-1W4. In 2003, Freehold Resources acquired a 23.52% working interest in 160 acres in the northern portion of Section 23, which lies directly south of Section 26. The Hayter Dina B pool is situated in the northeast portion of Township 40 Range 1 W4M covering portions of six sections. The pool produces 15° API oil from an average net pay interval of approximately 11 metres. The pool was discovered and delineated with vertical wells but due to the presence of an active bottom water drive has been more effectively developed with horizontal drilling. In 2003, 9 (2.1 net) wells were drilled. An additional 10 (2.4 net) wells are planned to be drilled in 2004. There are also plans to expand the water injection facilities to return shut-in wells to production.

Pembina Cardium Unit No. 9, Alberta

Freehold Resources has a 9.97% working interest and a 0.6% royalty interest in the Pembina Cardium Unit No. 9 located 85 miles southwest of Edmonton. Light oil production is from part of the Pembina oilfield, the largest conventional oilfield discovered in Canada. This production unit encompasses approximately 25,280 acres. This property has an extremely long reserve life and has been on an 80-acre, five-spot waterflood pattern for more than 40 years. In 2003, the producing reserve life of this property was truncated at 50 years from 2003 (no reserves after 2053), as recommended under NI 51-101. This resulted in negative revisions of 476 mboe of proved plus probable reserves. Subject to annual review, a portion of these reserves may be added back each year. In 2003, 26 (2.6 net) wells were drilled in the unit. The operator has plans to drill an additional 25 (2.5 net) infill wells in 2004.

Luseland, Saskatchewan

In 2001, Freehold Resources acquired a 20% working interest in 520 acres in the Luseland area of Saskatchewan, located 75 miles southwest of North Battleford. This property produces from the Middle Bakken Sandstone, which is of Lower Mississippian age. Averaging about 10 metres of high quality pay, this fine grained unconsolidated sand reservoir contains 13° API heavy oil. Production decreased 37% to 115 boe/d in 2003. The operator currently has no drilling plans for 2004.

Pouce Coupe, Alberta

Freehold Resources owns a 25.56% interest in the Pouce Coupe South Boundary "B" Unit #2 in west central Alberta. This property is under waterflood and produces light oil from the Boundary Lake formation. Production from this unit increased 5% to approximately 100 boe/d in 2003. In 2003, the operator shot a 3D seismic program that covered the unit. 2004 plans include the drilling of one well within the unit.

Other Working Interest Properties

The Trust has working interests in 68 other properties, which accounted for 42% of the working interest production volumes during 2003. Development activities included 39 (2.2 net) wells. The majority of the wells were drilled at Ring Border.

Working Interest Wells

The following table sets forth the number and status of wells as at December 31, 2003 in which Freehold Resources has a working interest which are producing or which are considered capable of production:

Property	Producing ⁽¹⁾				Non-Producing ⁽¹⁾⁽²⁾⁽³⁾			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Hayter	89	20.9	-	-	21	4.9	-	-
Pembina Cardium Unit No. 9	159	15.8	-	-	10	1.0	-	-
Luseland	9	1.8	-	-	2	0.4	-	-
Pouce Coupe South Boundary "B" Unit #2	11	2.8	-	-	1	0.3	-	-
Other (68 properties)	512	36.4	407	9.6	146	9.5	55	3.5
TOTAL	780	77.8	407	9.6	180	16.1	55	3.5

Notes:

(1) Based on public records.

(2) "Non-producing" wells means wells which are not producing but which are considered capable of production. Non-producing wells in which Freehold Resources has an interest are located no further than ten kilometers from gathering systems, pipeline or other means of transportation.

(3) Not all wells owned by Freehold Resources have been assigned reserves in the Trimble Report.

Development Activities

The following table sets forth the gross and net working interest development wells in which the Trust participated during the year ended December 31, 2003:

Years ending December 31	2003		2002	
	Gross	Net	Gross	Net
Development				
Oil	39	6.6	32	4.8
Natural Gas	35	0.3	22	0.1
Dry	-	-	-	-
TOTAL	74	6.9	54	4.9

Reconciliation of Working Interest Property Reserves

The following table provides a summary of the changes in working interest share of oil, and natural gas reserves based on forecast prices and costs, which occurred in the period commencing December 31, 2002 and ending December 31, 2003:

Factors	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas		
	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable
	(mbbls)	(mbbls)	(mbbls)	(mbbls)	(mbbls)	(mbbls)	(mmcf)	(mmcf)	(mmcf)
December 31, 2002 ⁽¹⁾	3,293	495	3,789	1,878	854	2,732	7,222	1,714	8,936
Extensions	26	9	35	-	-	-	-	-	1
Improved recovery	-	5	5	-	-	-	-	-	-
Technical revisions	(608)	75	(533)	(59)	386	327	(1,380)	(160)	(1,540)
Discoveries	-	3	3	-	-	-	48	10	58
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(46)	-	(46)	-	-	-	-	-	-
Economic factors	6	2	8	(9)	(6)	(15)	(43)	(14)	(57)
Production	(134)	(2)	(136)	(289)	2	(287)	(690)	(9)	(698)
December 31, 2003	2,537	588	3,125	1,522	1,236	2,758	5,157	1,541	(6,699)

Notes:

(1) The evaluation as at December 31, 2002 was prepared using National Policy 2-B reserves definitions. Under those definitions, probable reserves were adjusted by a factor to account for the risk associated with their recovery. The Trust previously applied a risk factor of 50% in reporting probable reserves. Under current NI 51-101 reserves definitions, estimates are prepared such that the full proved plus probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "best estimate"). The above reconciliation reflects current probable reserves versus previous risk adjusted (50%) probable reserves reported by the Trust.

(2) Columns may not add due to rounding.

Oil and Natural Gas Wells

The following tables set forth, by province, the number and status of wells in which the Trust has an interest as at December 31, 2003.

Working Interest Properties	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	617	62.3	145	14.4	249	9.2	45	2.9
British Columbia	14	0.4	5	0.2	158	0.4	9	0.1
Saskatchewan	134	13.9	27	1.3	-	-	1	0.5
Manitoba	15	1.1	3	0.2	-	-	-	-
Total	780	77.8	180	16.1	407	9.6	55	3.5

Royalty Lands ⁽¹⁾	Non-Unitized		Unitized	
	Natural Gas Wells	Oil Wells	Natural Gas Wells	Oil Wells
Alberta	1,175	946	4,694	3,722
British Columbia	-	-	-	-
Saskatchewan	399	1,135	38	3,440
Manitoba	-	18	-	26
TOTAL	1,574	2,099	4,732	7,188

Notes:

(1) Gross wells in which the Trust has a royalty interest.

Properties with No Attributable Reserves

The following table sets out the Trust's undeveloped land holdings as at December 31, 2003.

	Undeveloped Acres		
	Royalty Lands	Working Interest Lands	
	Gross	Gross	Net
Alberta	54,429	33,344	5,014
British Columbia	-	5,953	19
Saskatchewan	144,713	2,219	701
Manitoba	1,507	40	-
Total	200,649	41,556	5,734

There are no material work commitments on the undeveloped land holdings.

Tax Horizon

The Trust is a mutual fund trust under the Tax Act and distributes all of its taxable income to the Unitholders. By doing so, exposure to current tax at the Trust level is eliminated. In addition, the Trust is exempt from future income taxes because it is contractually committed to distribute all of its income to Unitholders.

Capital Expenditures

Freehold Resources may approve future capital expenditures or farmouts on Freehold Resources Properties under the terms of the Freehold Resources Royalty Agreement. Future capital expenditures are anticipated to be of the type which are intended to maintain or improve production from the Freehold Resources Properties. Freehold Resources may finance capital expenditures from Freehold Resources Royalty Income, additional issuances of Trust Units, borrowings, farmouts or with working capital of Freehold Resources. Freehold Resources will not initiate any exploratory drilling but may participate in exploratory drilling initiated by the operator of a property where, in the opinion of Freehold Resources, to do so would be in the best interests of the Trust. Under the terms of the Freehold Resources Royalty Agreement, annual capital expenditures (including acquisitions of Additional Properties) will not exceed 15% of the annual net cash flow from the HB Lands Royalties, Additional Royalties and the Freehold Resources Properties unless financed with borrowings, additional issuances of Trust Units or Freehold Resources Royalty disposition proceeds.

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Trust's activities for the year ended December 31, 2003:

	(\$000s)
Property acquisition costs	
Proved properties	3,386
Undeveloped/unproved properties	-
Development costs	5,894
Total	9,280

Production Estimates

The following table sets out the volume of Net production estimated in the Trimble Report for the year ended December 31, 2004, which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data".

2004 Forecast Net Production	
Light and Medium Oil (bbls/d)	1,290
Heavy Oil (bbls/d)	2,342
Natural Gas (mmcf/d)	9,312
Natural Gas Liquids (bbls/d)	275
Oil Equivalent (boe/d)	5,459

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

(6:1)	Quarter Ended			
	2003			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production⁽¹⁾				
Light and Medium Oil (bbls/d)	1,565	1,628	1,600	1,618
Heavy Oil (bbls/d)	2,174	2,153	1,923	2,089
Natural Gas (mmcf/d)	10.4	10.7	11.4	11.0
Natural Gas Liquids (bbls/d)	293	338	330	309
Combined (boe/d)	5,768	5,909	5,746	5,847
Average Price Received				
Light and Medium Oil (\$/bbl)	35.48	37.07	36.70	46.69
Heavy Oil (\$/bbls)	23.64	27.07	26.74	34.78
Natural Gas (\$/mcf)	5.25	5.73	6.39	7.29
Natural Gas Liquids (\$/bbls)	29.45	28.91	29.40	36.36
Combined (\$/boe)	29.51	32.15	33.49	40.97
Royalties Paid				
Light and Medium Oil (\$/bbls)	0.82	1.27	1.29	1.20
Heavy Oil (\$/bbls)	0.59	0.77	0.86	1.21
Natural Gas (\$/mcf)	0.37	0.43	0.36	0.46
Natural Gas Liquids (\$/bbls)	1.80	1.70	2.59	3.19
Combined (\$/boe)	1.20	1.52	1.50	1.81
Operating Expenses (\$/boe)⁽²⁾				
Light and Medium Oil (\$/bbls)	3.84	2.17	2.86	3.03
Heavy Oil (\$/bbls)	3.87	3.78	3.76	3.10
Natural Gas (\$/mcf)	0.15	0.20	0.05	0.18
Natural Gas Liquids (\$/bbls)	1.06	1.19	0.32	1.38
Combined (\$/boe)	2.83	2.41	2.18	2.35
Netback Received (\$/boe)⁽³⁾				
Light and Medium Oil (\$/bbls)	30.82	33.63	32.56	42.47
Heavy Oil (\$/bbls)	19.18	22.52	22.12	30.47
Natural Gas (\$/mcf)	4.72	5.10	5.98	6.65
NGLs (\$/bbls)	26.59	26.02	26.49	31.79
Combined (\$/boe)	25.88	28.61	30.47	37.18

Notes:

- (1) Before deduction of royalty expenses.
- (2) Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.
- (3) Netbacks are calculated by subtracting royalty expenses and operating costs from revenues.

The following table indicates the Trust's average daily production from its important fields for the year ended December 31, 2003:

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
Royalty Lands					
Western Alberta	135	-	2,847	203	813
Bashaw/Leduc	131	3	1,078	16	329
Northeast Alberta	15	460	763	-	602
Saskatchewan Heavy Oil	-	713	411	1	782
Southeast Alberta	56	92	1,776	2	446
Hatton/Gull Lake	93	10	494	-	185
Southeast Saskatchewan	640	-	170	-	669
Other	48	-	550	6	146
	1,118	1,278	8,089	228	3,972
Working Interest Properties					
Hayter	-	547	21	3	553
Pembina Cardium Unit No. 9	179	-	510	42	306
Luseland	-	115	-	-	115
Pouce Coupe Southern Boundary "B" Unit #2	83	-	81	3	100
Other	222	146	2,171	41	771
	484	808	2,783	89	1,845
Total	1,602	2,086	10,872	316	5,817

Environmental Obligations – Reclamation Fund

Freehold Resources will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the Freehold Resources Properties upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

Freehold Resources currently estimates that the future environmental and reclamation obligations in respect of the Working Interest Properties will aggregate approximately \$7.0 million. A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. The funding level is reviewed and approved by the board of directors of Freehold Resources annually based on estimated future liabilities and spending profile.

Future abandonment and reclamation costs have been estimated based on actual costs incurred to date for abandonment and reclamation activities. The Trust expects to abandon and reclaim approximately 131 net wells at the estimated costs identified in the table below.

As at December 31, 2003	Abandonment and Reclamation Costs (Net of Salvage Value) (\$000s)	
	Undiscounted	Discounted at 10%
Total Costs as at December 31, 2003	7,000	1,564
Total Costs Not Deducted From Future Net Revenue	3,032	749
Expected to be paid in 2004	100	95
Expected to be paid in 2005	100	86
Expected to be paid in 2006	100	78

With respect to the HB Lands, the responsibilities for adherence to environmental regulations reside with the operators and working interest owners of the HB Lands and not with the Trust. Therefore, no reclamation fund has been established for the HB Lands.

OTHER INFORMATION RESPECTING FREEHOLD RESOURCES

Additional and Replacement Properties

Freehold Resources may acquire Additional Properties and related tangible equipment and fund such acquisitions from Freehold Resources Royalty Income, additional issuances of Trust Units, borrowings, farmouts or with working capital of Freehold Resources.

Freehold Resources may sell any of its interests in Freehold Resources Properties and release the Freehold Resources Royalty therefrom if it determines that such sale would be in the best interest of Unitholders. The Freehold Resources Royalty Agreement permits Freehold Resources to effect such sale provided that the sale is approved by a Special Resolution of the Unitholders in the event the interests in the Freehold Resources Properties being sold constitute greater than 50% of the Asset Value of all Freehold Resources Properties and provided such sale is approved by the board of directors of Freehold Resources for sales of Freehold Resources Properties for proceeds in excess of \$5.0 million. The proceeds of a disposition of an interest in the Freehold Resources Properties to the extent related to Canadian resource properties, as defined in the Tax Act, will be allocated 99% to the Trust, after retiring any borrowing which relates to the Canadian resource property component of such interest, in consideration for the release of the Freehold Resources Royalty from such Freehold Resources Properties.

In connection with the sale of any interests in the Freehold Resources Properties, Freehold Resources will determine whether the net proceeds of the sale should be distributed to Unitholders or reinvested and Freehold Resources may consider Replacement Properties for purchase.

Borrowing by Freehold Resources

Pursuant to the Freehold Resources Royalty Agreement, Freehold Resources is permitted to borrow funds to finance the purchase of Additional Properties, for capital expenditures or for other financial obligations or expenditures in respect of the Freehold Resources Properties or for working capital purposes. Freehold Resources has established guidelines which provide that: (a) the amounts borrowed to finance the purchase of Additional Properties when combined with existing debt of Freehold Resources and existing debt of the Trust will not exceed 40% of the Asset Value of all of the HB Lands Royalties, the Additional Royalties and the Freehold Resources Properties at the time of borrowing; and (b) the Debt Service Charges on amounts borrowed to finance the purchase of Additional Properties or capital expenditures to maintain or improve production from the Freehold Resources Properties or other borrowings as permitted above will not exceed 10% of the estimated annual Royalty Income. Freehold Resources will be entitled to grant security or guarantee the obligations of the Trust with respect to any borrowing by the Trust. See "Trust Units – Borrowing by the Trust".

Debt Service Charges will be deducted in computing Freehold Resources Royalty Income. The debt repayment will be scheduled to minimize, to the extent possible, any income tax payable by Freehold Resources.

Freehold Resources has entered into an agreement establishing a credit facility from a Canadian chartered bank to provide a revolving term loan facility of up to \$65.0 million for general corporate purposes including acquisitions. The outstanding principal amount of such facility bears interest at either the bank's Canadian dollar prime rate or bankers' acceptance rate, plus 90 to 165 basis points (based on certain debt to cash flow ratio) at the option of Freehold Resources.

In addition, Freehold Resources may borrow from the Trust without reference to the foregoing test at a commercial rate of interest, provided that the Trust funds such lending out by the sale of Trust Units or by borrowing.

Insurance

Freehold Resources carries insurance policies to provide protection for its working interest in the Freehold Resources Properties at or above industry standards. Insurance policies cover property damage, general liability and, for certain properties, business interruption. The ongoing level, type and maintenance of insurance are determined by Freehold Resources based upon the availability and cost of such insurance and Freehold Resources' perception of the risk of loss. Freehold Resources carries insurance which provides standard industry levels of coverage to individuals for all good faith acts carried out by them on behalf of the Corporation in their capacity as directors or officers of the Corporation.

POTASH INTERESTS AND RESERVES

Description of Potash Interests

In addition to royalties received on Petroleum Substances, the Trust also receives royalty income from leased potash rights. Potash is used to manufacture agricultural fertilizers.

The Trust has acquired the right to the revenue derived from Canpar's lessor royalty interest in over 9,750 gross acres of leases issued to various operators of seven potash mines, all located within the Province of Saskatchewan. These leases are included within larger potash units, which cover the total mine areas. Canpar originally acquired a 23.52% freehold mineral title interest in those potash properties leased to third parties as of January 1, 1979. The royalties derived from the potash leases are calculated in the same manner as royalties payable to the Province of Saskatchewan from provincially owned potash rights. Canpar subsequently entered into an agreement with its partners in 1993 with respect to the six mines producing at that time. It was agreed that Canpar would receive 100% of its partners' share of all potash royalties from leased and producing properties from an effective date of December 1, 1993, until the sum of \$3 million had been received. As payout occurred in the first half of 2000, ownership interest in the properties has reverted to 50% to the Trust and 50% to its partner.

The Trust also acquired a royalty interest in a seventh mine within a unit formed by Central Canada Potash in the Colonsay area of Saskatchewan. The Trust's unitized royalty interest is 7.52% and the mine, currently in production, is expected to be operational until at least the year 2011.

Potash Reserves

Due to the immaterial value of the potash reserves to the Trust, the Trust has not obtained a recent independent evaluation of the potash reserves attributable to the HB Lands Royalties. However, the Manager has internally generated a report evaluating, as at December 31, 2003, the potash reserves attributable to the HB Lands Royalties acquired by the Trust. The Potash Report evaluates the potash reserves attributable to the HB Lands Royalties prior to provision for income taxes, Debt Service Charges and General and Administrative Costs. It should not be assumed that the estimated discounted future net production revenues represent the fair market value of the reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized in the notes following the table.

Potash Reserves and Net Pre-Tax Cash Flows Constant and Escalated Price and Cost Case

	Trust Interest Potash Reserves		Present Net Value Of Future Net Pre-Tax Cash Flows (\$000)			
	(mtonnes)		Undiscounted	Discounted at		
	Gross ⁽¹⁾	Net ⁽¹⁾		5%	10%	15%
Proved Reserves						
Constant Price and Cost ⁽²⁾	60,352	60,352	14,897	7,507	4,943	3,738
Escalated Price and Cost ⁽³⁾	60,352	60,352	19,706	8,952	5,551	4,068

Notes:

(1) The following definitions have been used in the Potash Report:

- (a) "Proved Reserves" are those reserves estimated as recoverable under current technology and existing economic conditions from that portion of the ore body which can be reasonably evaluated as economically recoverable using mining processes demonstrated to be economic and technically successful.
- (b) "Net Production Revenue" is income derived from the sale of potash, less any capital and operating costs.

(2) The constant price and cost evaluation was based upon a potash price of Cdn. \$134.87 per tonne.

- (4) Average yearly potash prices, which were deemed appropriate as at December 31, 2003 for potash are outlined in the following table:

<u>Year</u>	<u>Price/tonne (\$Cdn.)</u>
2004	134.87
2005	136.90
2006	138.95
2007	141.03
2008	143.15
2009	145.30
2010	147.48
2011	149.69
2012	151.93
2013	154.22
Thereafter	1.5%/year

There are no operating and capital costs associated with these reserves.

- (4) The net production of potash in 2003 was 7.6 tonnes per day in both the constant and escalated price cases. The estimated undiscounted net pre-tax cash flow in 2004 is \$536,515 in both the constant and escalated price cases.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of the Trust which prospective investors should carefully consider before deciding whether to purchase Trust Units.

Reserve Estimates

The reserve and recovery information incorporated by reference herein are only estimates and the actual production and ultimate reserves from the Royalty Lands, the Additional Properties and the Working Interest Properties may be greater or less than the estimates prepared.

Volatility of Oil and Natural Gas Prices

The Trust's operational results and financial condition, and therefore the amounts paid to the Trust pursuant to the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty, will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices fluctuate and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions, all of which are beyond the control of the Trust and the Manager. Any decline in oil and natural gas prices could have an adverse effect on the Trust's financial condition and therefore on Distributions to Unitholders.

Foreign Exchange

Our operating costs are generally paid in Canadian dollars. World oil prices are quoted in U.S. dollars. The price that Canadian producers receive is therefore affected by the Canadian/U.S. dollar exchange rate. As experienced, that exchange rate may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our production revenue.

Depletion of Reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions to Unitholders in respect of properties, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. The Trust and Freehold Resources will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent capital injections, successful development or acquisition of additional reserves, the Trust and Freehold Resources will have difficulty maintaining current production levels and reserves.

The Trust's and Freehold Resources' future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on activities of the working interest owners of the Royalty Lands and Freehold Resources' success in exploiting its reserve base and acquiring additional reserves on the Freehold Resources Properties. Without reserve additions through acquisition or development activities, the Trust's and Freehold Resources' reserves and production will decline over time as reserves are exploited.

There can be no assurance that the Manager, on behalf of Freehold Resources, will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

Investment Eligibility

If the Trust ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for RRSPs, RESPs, RRIFs and DPSPs ("Exempt Plans"). Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the Exempt Plan. In addition, where a trust governed by an RRSP holds Trust Units that are not qualified investments, the trust will become taxable on its income attributable to the Trust Units while they are not qualified investments.

Operational Matters

The operation of oil and natural gas wells involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to Freehold Resources and possible liability to third parties. Freehold Resources will maintain liability insurance, where available, in amounts consistent with industry standards. Business interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. Freehold Resources may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce Freehold Resources Royalty Income.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of Freehold Resources to certain Working Interest Properties. A reduction of the Freehold Resources Royalty Income could result in such circumstances.

Environmental Concerns

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of Freehold Resources or the Freehold Resources Properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Freehold Resources. Although Freehold Resources has established a reclamation fund for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that the Trust will be able to satisfy actual future environmental and reclamation obligations.

Debt Service

Amounts paid in respect of interest and principal on debt incurred in respect of the HB Lands Royalties, the Additional Royalties, the Additional Properties and the Working Interest Properties will reduce Royalty Lands Royalty Income and Freehold Resources Royalty Income. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of the Royalty Lands Royalty Income and Freehold Resources Royalty Income and Distributions to Unitholders. Certain covenants of the agreements with the lender may also limit distributions to the Trust. Although the Manager and Freehold Resources believe the credit facility is sufficient for the Trust's and Freehold Resources' immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of the Trust or Freehold Resources or that additional funds will be able to be obtained.

The lender has been provided with security over substantially all of the assets of the Trust and Freehold Resources. If the Trust or Freehold Resources becomes unable to pay its Debt Service Charges or otherwise commits an event of

default such as bankruptcy, the lender may foreclose on or sell all or some of the HB Lands Royalties, the Additional Royalties, Additional Properties and the Working Interest Properties free from or together with the Freehold Resources Royalty.

Delay in Cash Distributions

In addition to the usual delays in payment by purchasers of oil and natural gas to the payors of the HB Lands Royalties, the Additional Royalties and/or operators of the Freehold Resources Properties, and by those payors and operators to the Manager or Freehold Resources, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operators of expenses incurred in the operation of the Freehold Resources Properties or the establishment by the operators of reserves for such expenses.

Reliance on the Manager

Unitholders are dependent on the management of the Manager in respect of the administration and management of all matters relating to the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty, the Trust and Trust Units. Investors who are not willing to rely on the management of the Manager should not invest in the Trust Units.

Additional Financing

To the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, the Trust's and Freehold Resources' ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that the Trust or Freehold Resources is required to use cash flow to finance capital expenditures or property acquisitions, the level of Distributions to Unitholders will be reduced.

Competition

There is strong competition relating to all aspects of the oil and gas industry. The Trust and Freehold Resources will actively compete for reserve acquisitions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and other resources than the Trust or Freehold Resources.

Potential Conflicts of Interest

There may be circumstances in which the interests of the Manager will conflict with those of Unitholders. The Manager may acquire oil and natural gas properties on its own behalf or on behalf of persons other than the Unitholders. The Manager may manage and administer such additional properties, as well as enter into other types of energy-related management, advisory and investment activities. Neither the Manager, nor its management, will carry on their full-time activity on behalf of Unitholders and, when acting on their own behalf or on behalf of others, may at times act in competition with the interests of Unitholders.

Circumstances may arise where members of the board of directors of Freehold Resources are directors or officers of corporations which are in competition to the interests of Freehold Resources and the Trust. No assurances can be given that opportunities identified by such board members will be provided to Freehold Resources and the Trust. See "Conflicts of Interest".

Changes in Legislation

There can be no assurance that income tax laws and government incentive programs relating to the oil and gas industry, such as ARC and the resource allowance, will not be changed in a manner which adversely affects Unitholders.

Title

Although satisfactory title reviews of the properties are conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Trust to a property. A reduction of Royalty Income could result in those circumstances.

Nature of Trust Units

Securities such as Trust Units are hybrids in that they share certain attributes common to both equity securities and debt instruments. The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in Freehold Resources. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring “oppression” or “derivative” actions. The Trust’s sole assets will be Permitted Investments, the HB Lands Royalties, Additional Royalties and the Freehold Resources Royalty. The price per Trust Unit is a function of anticipated Distributions to Unitholders, the HB Lands Royalties, the Additional Royalties and the Freehold Resources Royalty and Manager’s ability to effect long-term growth in the value of the Trust. The market price of the Trust Units is sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

Return of Capital

Trust Units will have no value when reserves from the HB Lands Royalties, the Additional Royalties and/or the Freehold Resources Properties can no longer be economically marketed and, as a result, investors will have to obtain the return of capital invested out of cash distributions during the period when reserves can be economically recovered.

Cash on Cash Yield

Cash on cash yield is a useful and widely used supplemental measure that provides investors with information on cash actually distributed relative to trading price. Unitholders are cautioned that cash on cash yield does not have any standardized meaning prescribed by generally accepted accounting principles (“GAAP”) and should not be construed as an alternate to net income as determined by GAAP. Unitholders are also cautioned that cash on cash yield represents a blend of return of investors initial investment and a return on investors initial investment and is not comparable to traditional yield on debt instruments where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments.

Potential for Write-Downs

Under Canadian accounting rules, a “ceiling limit” test is applied to the carrying value of oil and natural gas assets, net of the provision for site restoration, plus future development costs, to ensure that such costs do not exceed future estimated net revenues from production of proved reserves at year-end prices and costs. A severe decline in oil and natural gas prices could cause our capitalized costs to exceed the cost ceiling. If our net capitalized costs exceed this “ceiling limit” we must charge the amount of the excess against earnings. Although this charge to earnings, or write-down, would not affect cash flow, such a charge could be viewed unfavorably in the market and it may also affect of ability to borrow funds or to comply with covenants in our credit arrangements, current or future.

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder will be subject to any liability in connection with the Trust or its obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of the Trust’s assets. Pursuant to the Trust Indenture, the Trust will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Personal liability may also arise in respect of claims against the Trust that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely.

The operations of the Trust are conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the Unitholders for claims against the Trust.

TRUST UNITS

The Trust Indenture

An unlimited number of Trust Units have been created and may be issued pursuant to the Trust Indenture. The Trust Units represent equal undivided beneficial interests in the Trust. All Trust Units share equally in all distributions from the Trust and all Trust Units carry equal voting rights at meetings of Unitholders. No Unitholder will be liable to pay any further calls or assessments in respect of the Trust Units.

The Trust Indenture, among other things, provides for the calling of meetings of Unitholders, the conduct of business thereof, notice provisions, the appointment and removal of the Trustee and the form of Trust Unit certificates. The Trust Indenture may be amended from time to time. Substantive amendments to the Trust Indenture, including early termination of the Trust and the sale or transfer of the property of the Trust as an entirety or substantially as an entirety requires approval by Special Resolution of the Unitholders. See "Trust Units - Meetings and Voting".

The following is a summary of certain provisions of the Trust Indenture. For a complete description of such indenture, reference should be made to the Trust Indenture, which is available on SEDAR at www.sedar.com or may be viewed at the offices of, or obtained from, the Trustee.

Trustee

Computershare Trust Company of Canada (the "Trustee") is the trustee of the Trust. The Trustee also acts as the transfer agent and registrar for the Trust Units, from their offices located in Calgary, Alberta and Toronto, Ontario. The Trustee is responsible for, among other things: (a) accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto; (b) maintaining books and records of the Trust and providing timely reports to holders of Trust Units; and (c) paying cash distributions to Unitholders. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The Trustee may resign upon 60 days notice to Freehold Resources and the Manager. The Trustee may also be removed by Special Resolution of the Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

The Trust has retained the Manager to administer the Trust on behalf of the Trustee. The Manager, on behalf of the Trustee, keeps such books and records as are necessary for the proper recording of the business transactions of the Trust.

The Trust Indenture provides that the Trustee shall be under no liability for any action or failure to act unless such liabilities arise out of the Trustee's gross negligence, willful default or fraud. The Trustee, where it has met its standard of care, shall be indemnified out of the assets of the Trust in consequence of its performance of its duties but shall have no additional recourse against Unitholders. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Cash Distributions of Royalty Income

Cash distributions are made on a monthly basis on the 15th day of the month following each Record Date to Unitholders of record on the Record Date.

The actual amount of Distributions to Unitholders will depend on, among other things, the quantity of oil, natural gas, natural gas liquids and potash produced, prices received, General and Administrative Costs, direct expenses of the Trust, Capital Expenditures, Debt Service Charges, Crown royalties and other Crown charges, net contributions to Freehold Resources' reclamation fund, and interest income.

By utilizing available tax deductions, cash distributions in the Trust's initial years were sheltered from income tax. The Trust paid \$1.70 per Trust Unit in cash distributions during 2003. For Canadian tax purposes, 69% of these distributions (\$1.1730 per Trust Unit) were taxable to Unitholders as other income and 31% (\$0.5270 per Trust Unit) was tax deferred (return of capital). Over time, an increasing percentage of the annual distributions will become taxable. Based on production and commodity price forecasts, it is estimated that approximately 25% of Distributions to the Unitholders will be tax deferred in 2004 and 75% will be taxable.

Income Tax Considerations

Future acquisitions of Canadian resource properties would result in royalty payments to the Trust and, in turn, Distributions to Unitholders that would, under most circumstances, be on the same tax deferred basis as are current distributions. Future acquisitions of corporations, facilities or other forms of oil and natural gas assets may result in dividend, interest or other forms of payments to the Trust (as opposed to royalty payments) and, in turn, Distributions to Unitholders that may be wholly or in part taxable. In approving any future acquisition, the board of directors of Freehold Resources would be required to consider the impact that such acquisition would have on anticipated after-tax Distributions to Unitholders.

Right of Redemption

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to the Trust of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requesting redemption. Upon receipt of the redemption request by the Trust, all rights to and under the Trust Units tendered for redemption shall be surrendered and the holder thereof shall be entitled to receive a price per Trust Unit ("Market Redemption Price") equal to the lesser of: (i) 90% of the market price of the Trust Units on The Toronto Stock Exchange or if not trading on The Toronto Stock Exchange at such time the principal market on which the Trust Units are quoted for trading at such time (the "Principal Market") during the 10 trading day period commencing immediately after the date on which the Trust Units are surrendered for redemption; and (ii) 90% of the "closing market price" on the Principal Market on which the Trust Units are quoted for trading on the date that the Trust Units are surrendered for redemption.

The aggregate cash Market Redemption Price payable by the Trust in respect of any Trust Units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month; provided that the entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitations that: (i) the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for retraction in the same calendar month shall not exceed \$100,000 provided that such limitation may be waived at the discretion of the board of directors of Freehold Resources in respect of any calendar month; (ii) at the time such Trust Units are tendered for retraction the outstanding Trust Units of the Trust shall be listed for trading on a stock exchange or traded or quoted on any other market which the board of directors of Freehold Resources consider, in its sole discretion, provided representative fair market value prices for the Trust Units and on which market price can be calculated; or (iii) the normal trading of Trust Units is not suspended or halted on any stock exchange on which the Trust Units are listed (or, if not listed on a stock exchange, on any market on which the Trust Units are quoted for trading) on the date that the Trust Units are tendered for retraction or for more than five trading days during the ten day trading period commencing immediately after the date on which the Trust Units are tendered for retraction.

If a Unitholder is not entitled to receive cash upon the redemption of Trust Units as a result of the foregoing limitations, then the Market Redemption Price for such Trust Units shall be paid on the last day of the following month by the Trust distributing Freehold Resources Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption but not redeemed as provided above.

If at the time Trust Units are tendered for redemption by a Unitholder the outstanding Trust Units are not listed for trading on The Toronto Stock Exchange and are not traded or quoted on any other stock exchange or market which Freehold Resources considers in its sole discretion, provides representative fair market values for the Trust Units or trading of the outstanding Trust Units is suspended or halted on the date such Trust Units tendered for redemption or for more than five trading days during the 10 trading days commencing immediately after the date such Trust Units were tendered for redemption then such Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the "Appraised Redemption Price") equal to 90% of the fair market value thereof as determined by Freehold Resources as at the date upon which such Trust Units were tendered for redemption. The aggregate Appraised Redemption Price payable by the Trust in respect of Trust Units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at the option of Freehold Resources: (i) a cash payment, or (ii) a distribution of Freehold Resources Notes.

The Freehold Resources Notes, if and when needed, are proposed to be created and issued by Freehold Resources to the Trust pursuant to a note indenture and are to be unsecured and bear interest from the date of issue at the lessor of: (a) the interest paid on two year Government of Canada bonds minus 2%; or (b) 6% per annum. A new series of Freehold Resources Notes will be created and issued for each monthly redemption of Trust Units, if any. The Freehold Resources Notes are due and payable on maturity on the 15th anniversary of the date of issuance.

The holder of the Freehold Resources Notes of a particular series (equal in principal amount to the Market Redemption Price or Appraised Redemption price, as the case may be, of one Trust Unit for a particular series) will be paid interest and principal, if any, monthly, in arrears on the 20th day of the next following month (and interest will only be deemed to accrue and principal to be payable only to the extent of the amount calculated hereunder) in an amount calculated in accordance with the following formula:

$$\frac{\text{RUU}}{\text{All RUU} + \text{All OS}} \quad \times \quad \text{Distributions to Unitholders}$$

Where:

RUU	means the number of the redeeming Unitholder's Units tendered for redemption.
All RUU	means the aggregate of the number of the redeeming Unitholders' Units tendered for redemption.
All OS	means all of the issued and outstanding Units.
Distributable Income	means the amounts held by the Trust which are to be actually distributed to Unitholders for the applicable month.

All amounts paid will be applied firstly to interest and then to principal. Any interest not paid when due will not bear interest but will be carried forward to the next interest payment date.

The Freehold Resources Notes may be prepaid at any time without notice, bonus or penalty at the discretion of the board of directors of Freehold Resources and will be prepaid to the extent the sale of resource properties increases Distributions to Unitholders. The Freehold Resources Notes will be paid in full in cash or in specie prior to any Distributions to Unitholders in the event of the dissolution or winding-up of the Trust.

The Freehold Resources Notes will be in default and become immediately due and payable on the occurrence of the following events of default: (i) default in payments of principal or interest when due for a period of three months, (ii) default by Freehold Resources on indebtedness exceeding \$10.0 million, (iii) certain events of insolvency, bankruptcy, winding-up or receivership, (iv) taking of possession of all or substantially all of the property of Freehold Resources by an encumbrancer, or (v) breach of any material term of the note indenture for a period of 30 days after notice of breach.

The Freehold Resources Notes will be unsecured debt obligations of the Trust and will be subordinate to any "senior indebtedness" which includes all indebtedness for borrowed money (or for the purchase of property) on any default in payment of any such senior indebtedness and to all trade debt of the Trust or Freehold Resources or any subsidiary of either of them or any creditor proceedings such as bankruptcy, liquidation or insolvency.

It is anticipated that this retraction right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Freehold Resources Notes which may be distributed in specie to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in the Freehold Resources Notes. Freehold Resources Notes may be subject to resale restrictions under applicable securities laws. Freehold Resources Notes so distributed may be qualified investments for trusts governed by registered retirement savings plans, registered retirement income trusts and deferred profit sharing plans.

Future Offerings

Under the Trust Indenture, the Trust may offer additional Trust Units or rights to acquired additional Trust Units at such times and on such terms as the board of directors of Freehold Resources may determine. Pursuant to the Deferred Purchase Price Obligation, the Freehold Resources Royalty will attach to the interests of Freehold Resources in any Additional Properties it may acquire from time to time. Accordingly, the proceeds from any offerings of Trust Units will be used to finance the acquisition of Additional Royalties by the Trust or Additional Properties should such interests be available on terms and conditions acceptable to Freehold Resources on behalf of Unitholders.

Borrowing by the Trust

Pursuant to the Trust Indenture, the Trust will be permitted to borrow funds to finance the purchase of Additional Royalties, for capital expenditures or for other financial obligations or expenditures in respect of the HB Lands Royalties and Additional Royalties or for working capital purposes and to grant security on the HB Lands Royalties and Additional Royalties to secure the loan of such funds. The Trust has established guidelines which provide that: (a) the amounts borrowed to finance the purchase of Additional Royalties when combined with existing debt of the Trust and existing debt of Freehold Resources will not exceed 40% of the Asset Value of all of the HB Lands Royalties, the Additional Royalties and the Freehold Resource Properties at the time of borrowing; and (b) the Debt Service Charges on amounts borrowed to finance the purchase of Additional Royalties or capital expenditures to maintain or improve production from the HB Lands Royalties or other borrowing as permitted above will not exceed 10% of the estimated annual Royalty Income.

Debt Service Charges incurred by the Trust will be deducted in computing Distributions to Unitholders. The debt repayment will be scheduled to minimize, to the extent possible, any income tax payable by the Trust.

Meetings and Voting

Annual meetings of the Unitholders are held annually. Special meetings of Unitholders may be called at any time by the Trustee and shall be called by the Trustee upon the written request of Unitholders holding in aggregate not less than 20% of the Trust Units. Notice of all meetings of Unitholders shall be given to Unitholders at least 21 days prior to the meeting.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and proxyholder need not be a holder of Trust Units. At least two persons present in person or represented by proxy and representing in the aggregate not less than 10% of the votes attaching to all outstanding Trust Units constitute a quorum for the transaction of business at all such meetings.

Unitholders are entitled to one vote per Trust Unit at all meetings of Unitholders called pursuant to the Trust Indenture. A Special Resolution of Unitholders is required to, among other things, make certain amendments to the Trust Indenture, remove the Trustee or terminate the Trust.

Management of the Trust

Pursuant to the provisions of the Management Agreement, the Manager provides certain administrative and support services to the Trust, including those necessary: (i) to ensure compliance by the Trust with continuous disclosure obligations under applicable securities legislation; (ii) to provide investor relations services; (iii) to provide or cause to be provided to Unitholders all information to which Unitholders are entitled under the Trust Indenture; (iv) to call, hold and distribute materials including notices of meetings and information circulars in respect of all necessary meetings of Unitholders; (v) to determine the amounts payable from time to time to Unitholders and to arrange for Distributions to Unitholders; (vi) to determine the timing and terms of future offerings of Trust Units, if any; (vii) to determine the terms and conditions upon which the Trust may acquire Additional Royalties; and (viii) to determine the terms and conditions upon which the Trust may from time to time borrow money. The board of directors of Freehold Resources is required to approve all matters referred to in items (iv), (v), (vi), (vii) and (viii) above and, in addition will be required to approve any amendment to the Management Agreement, the HB Lands Royalty Agreement or the Freehold Resources Royalty Agreement.

Limitation on Non-Resident Ownership

In order for the Trust to maintain its status as a mutual fund trust under the Tax Act, the Trust must not be established or maintained primarily for the benefit of non-residents of Canada ("non-residents") within the meaning of the Tax Act. Accordingly, the Trust Indenture provides that at no time may non-residents be the beneficial owners of a majority of the Trust Units. If the Trustee becomes aware that the beneficial owners of 49% of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, the Trustee may make a public announcement thereof and shall not accept a subscription for Trusts Units from or issue or register a transfer of Trust Units to a person unless the person provides a declaration that the person is not a non-resident. Notwithstanding the foregoing, if the Trustee determines that a majority of the Trust units are held by non-residents, the Trustee may send a notice to non-resident holders of Trust Units, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustee may consider equitable and practicable, requiring them to sell their Trust Units or a portion thereof within a specified period of not less than 60 days. If the Unitholders receiving such notice have not sold the specified number of Trust Units or provided the Trustee with satisfactory evidence that they are not non-residents within such period, the Trustee may on behalf of such Unitholders sell such Trust Units and, in the interim,

shall suspend the voting and payment of Distributions to Unitholders and other rights attached to such Trust Units and shall make any distribution in respect of such Trust Units by depositing such amounts in a separate bank account. Upon such sale, the affected holders shall cease to be holders of Trust Units and their rights shall be limited to receiving the net proceeds of sale upon surrender of the certificates representing such Trust Units.

Termination of the Trust

The Unit holders may vote to terminate the Trust at any meeting of the Unitholders, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% of the Trust Units or the Trust Units have become ineligible for investment by RRSPs, RESPs, RRIFs or DPSPs; (b) a quorum of 50% of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by Special Resolution of the Unitholders.

Unless the Trust is terminated or extended by vote of the Unitholders earlier, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2096. In the event that the Trust is wound-up, the Trustee will liquidate all the assets of the Trust, pay, retire, discharge or make provision for some or all obligations of the Trust and then distribute the remaining proceeds of sale to the Unitholders.

Reporting to Unitholders

The financial statements of the Trust are audited annually by an independent recognized firm of chartered accountants. The auditors of the Trust are KPMG LLP, Chartered Accountants. The audited financial statements of the Trust, together with the report of such chartered accountants, are mailed by the Trustee to Unitholders and the unaudited interim financial statements of the Trust are mailed to Unitholders within the periods prescribed by securities legislation. The year end of the Trust is December 31. The Trust is subject to the continuous disclosure obligations under all applicable securities legislation.

Unitholders are entitled to inspect, during normal business hours, at the offices of the Trustee, and, upon payment of reasonable reproduction costs, to receive photocopies of the HB Lands Royalty Agreement (other than schedules), the Freehold Resources Royalty Agreement (other than schedules), the Trust Indenture, the Management Agreement and a listing of the registered holders of Trust Units.

Distribution Policy

Distributions to Unitholders consist of Royalty Income, ARC and other income received by the Trust less royalties, expenses and withholdings payable by the Trust and less other amounts reasonably determined by Freehold Resources to be retained for the purposes of the Trust.

The Trust retains cash to, among other things, fund capital expenditures or acquisitions, and reduce bank indebtedness. The distribution policy allows the use of up to 15% of net cash flow for capital expenditures, including minor acquisitions, as determined under the Trust Indenture. The Trust's distribution policy includes withholding a portion of cash available for distribution to contribute to the Trust's reclamation fund to provide a cash reserve for the eventual abandonment of oil and gas properties.

Regular distributions are made to Unitholders on a monthly basis. On a quarterly basis, the board of directors of Freehold Resources reviews the application of any cash available for distribution in excess of these amounts. The board of directors' policy has been to apply some portion, up to 50%, of funds in excess of regular monthly distributions to the repayment of debt and/or working capital improvement, with the remainder distributed to Unitholders as an extra distribution. The actual percentage retained by the Trust is subject to the discretion of the board of directors of Freehold Resources.

Distribution History

Cash distributions are made on the 15th day of the month following each Record Date to Unitholders of record on the Record Date. Royalty Income and consequently Distributions to Unitholders are determined on a cash received basis.

The table below sets forth the amount of cash distributions the Trust has paid on the Trust Units for the three most recently completed financial years:

Record Date	Payment Date	Per Trust Unit (\$)
2001		
Dec. 31, 2000	Jan. 15, 2001	0.1000
Jan. 31, 2001	Feb. 15, 2001	0.1000
Feb. 28, 2001	Mar. 15, 2001	0.2000 ⁽¹⁾
Mar. 31, 2001	Apr. 15, 2001	0.1000
Apr. 30, 2001	May 15, 2001	0.1000
May 31, 2001	Jun. 15, 2001	0.2300 ⁽¹⁾
Jun. 30, 2001	Jul. 15, 2001	0.1200
Jul. 31, 2001	Aug. 15, 2001	0.1200
Aug. 31, 2001	Sep. 15, 2001	0.1700 ⁽¹⁾
Sep. 30, 2001	Oct. 15, 2001	0.1200
Oct. 31, 2001	Nov. 15, 2001	0.1000
Nov. 30, 2001	Dec. 15, 2001	0.1000
		1.5600
2002		
Dec. 31, 2001	Jan. 15, 2002	0.1000
Jan. 31, 2002	Feb. 15, 2002	0.0800
Feb. 28, 2002	Mar. 15, 2002	0.0800
Mar. 31, 2002	Apr. 15, 2002	0.0800
Apr. 30, 2002	May 15, 2002	0.0800
May 31, 2002	Jun. 15, 2002	0.1400 ⁽¹⁾
Jun. 30, 2002	Jul. 15, 2002	0.1000
Jul. 31, 2002	Aug. 15, 2002	0.1000
Aug. 31, 2002	Sep. 15, 2002	0.1700 ⁽¹⁾
Sep. 30, 2002	Oct. 15, 2002	0.1000
Oct. 31, 2002	Nov. 15, 2002	0.1000
Nov. 30, 2002	Dec. 15, 2002	0.1800 ⁽¹⁾
		1.3100
2003		
Dec. 31, 2002	Jan. 15, 2003	0.1000
Jan. 31, 2003	Feb. 15, 2003	0.1000
Feb. 28, 2003	Mar. 15, 2003	0.2000 ⁽¹⁾
Mar. 31, 2003	Apr. 15, 2003	0.1000
Apr. 30, 2003	May 15, 2003	0.1000
May 31, 2003	Jun. 15, 2003	0.3000 ⁽¹⁾
Jun. 30, 2003	Jul. 15, 2003	0.1000
Jul. 31, 2003	Aug. 15, 2003	0.1000
Aug. 31, 2003	Sep. 15, 2003	0.2000 ⁽¹⁾
Sep. 30, 2003	Oct. 15, 2003	0.1000
Oct. 31, 2003	Nov. 15, 2003	0.1000
Nov. 30, 2003	Dec. 15, 2003	0.2000 ⁽¹⁾
		1.7000

Note:

(1) Monthly distributions are supplemented by quarterly top-ups when excess income is available. Payment includes quarterly top up.

Unitholder Income Tax Information

All cash distributions paid to Unitholders from inception of the Trust to the end of the taxation year 2000 were 100% tax deferred and have been treated as a return of capital. Beginning in the taxation year 2001, the Trust's distributions became taxable. Cash distributions paid to Unitholders in 2001 were 62% tax deferred, 2002 distributions were 42% tax deferred, and 2003 distributions were 31% tax deferred.

2003 Canadian Resident Unitholder Taxation

Distributions received in the year 2003 were 69% taxable (other income) and 31% tax deferred (return of capital). Unitholders are required to report any taxable income resulting from distributions on their 2003 personal income tax returns.

Record Date	Payment Date	Taxable Amount (\$)	Return of Capital Amount (\$)	Total Distribution Paid (\$)
December 31, 2002	January 15, 2003	0.0690	0.0310	0.10
January 31, 2003	February 15, 2003	0.0690	0.0310	0.10
February 28, 2003	March 15, 2003	0.1380	0.0620	0.20
March 31, 2003	April 15, 2003	0.0690	0.0310	0.10
April 30, 2003	May 15, 2003	0.0690	0.0310	0.10
May 31, 2003	June 15, 2003	0.2070	0.0930	0.30
June 30, 2003	July 15, 2003	0.0690	0.0310	0.10
July 31, 2003	August 15, 2003	0.0690	0.0310	0.10
August 31, 2003	September 15, 2003	0.1380	0.0620	0.20
September 30, 2003	October 15, 2003	0.0690	0.0310	0.10
October 31, 2003	November 15, 2003	0.0690	0.0310	0.10
November 30, 2003	December 15, 2003	0.1380	0.0620	0.20
Total paid during the 2003 taxation year		1.1730	0.5270	1.70

2004 Taxability

The Trust estimates that approximately 25% of Distributions to Unitholders received in 2004 will be tax deferred and 75% will be taxable. The actual level of taxability is dependent upon commodity prices received and company activities undertaken to year-end.

Non-Resident Unitholder Taxation

FOR FOREIGN TAXPAYERS

The following information is provided for general information only. Unitholders who are not residents of Canada for income tax purposes are encouraged to seek advice from a qualified tax advisor in their country of residence for the tax treatment of distributions.

Non-Resident Withholding Tax

Monthly income distributions payable to non-residents of Canada are normally subject to a withholding tax of 25% as prescribed by the Income Tax Act (Canada). This withholding tax may be reduced in accordance with reciprocal tax treaties.

Tax Considerations for U.S. Residents

In the case of the Tax Treaty between Canada and the U.S., the withholding tax for U.S. residents is prescribed at 15%. U.S. taxpayers may be eligible for a foreign tax credit with respect to the Canadian withholding taxes paid. U.S. investors may also seek a refund of Canadian withholding tax related to amounts withheld on non-taxable distributions (from a Canadian tax perspective) from Canada Revenue Agency by filing Form NR7-R, Application for Refund of Non-Resident Tax Withheld.

The Trust has not made an election to be treated as a Partnership and is therefore deemed to be a Corporation for U.S. tax purposes.

U.S. tax rules state that no portion of the distribution will be considered a tax-deferred return of capital unless the trust computes its current and accumulated earnings and profits in accordance with U.S. income tax principles. **Because a current and accumulated earnings and profits calculation is not performed by Freehold at this time, distributions are 100% taxable to U.S. residents as a dividend. However, such dividends may be eligible for the lower U.S. tax rate allowed on dividends from certain foreign corporations. Please consult your U.S. tax advisor.**

Distributions are considered a dividend for tax reporting purposes. Registered Unitholders will receive a form NR4 from the Trustee. Non-registered Unitholders (units held by a brokerage firm or other intermediary) will receive a form NR4 from the brokerage firm or other intermediary.

2003 DISTRIBUTIONS IN U.S. DOLLARS

Record Date	Payment Date	Total Distribution Paid in CDN\$	Cdn./U.S. Exchange Rate\$	Total Distribution Paid in US\$
December 31, 2002	January 15, 2003	0.10	1.5796	0.063307
January 31, 2003	February 15, 2003	0.10	1.5215	0.065725
February 28, 2003	March 15, 2003	0.20	1.4871	0.134490
March 31, 2003	April 15, 2003	0.10	1.4693	0.068060
April 30, 2003	May 15, 2003	0.10	1.4335	0.069759
May 31, 2003	June 15, 2003	0.30	1.3708	0.218850
June 30, 2003	July 15, 2003	0.10	1.3553	0.073784
July 31, 2003	August 15, 2003	0.10	1.4073	0.071058
August 31, 2003	September 15, 2003	0.20	1.3851	0.144394
September 30, 2003	October 15, 2003	0.10	1.3504	0.074052
October 31, 2003	November 15, 2003	0.10	1.3197	0.075775
November 30, 2003	December 15, 2003	0.20	1.2973	0.154166
Total paid during the 2003 taxation year		1.70		1.213421

Direct Deposit Plan

A Direct Deposit Plan (the "Deposit Plan") has been established for the Trust to provide holders who have Canadian bank accounts with a method of receiving cash distributions as a direct deposit into their bank account.

Cash Distribution Reinvestment Plan

A Trust Unit Cash Distribution reinvestment plan (the "DRIP Plan") has been established for the Trust to provide Unitholders who are residents of Canada (within the meaning of the Tax Act) with a method of reinvesting cash distributions into new Trust Units.

US Currency Payment Plan

The US Currency Payment plan (the "US Currency Plan") allows holders of Trust Units of the Trust who maintain US currency accounts to obtain convenient payments in US currency.

CORPORATE GOVERNANCE

General

In general, Freehold Resources has been delegated the significant management decisions of the Trust. The Unitholders are entitled to elect a majority of the board of directors of Freehold Resources pursuant to the terms of the Unanimous Shareholder Agreement. Subject to the ultimate authority of the board of directors of Freehold Resources, Freehold Resources and the Trust are managed by the Manager.

Unanimous Shareholders Agreement

Pursuant to the Unanimous Shareholder Agreement dated November 25, 1996 among the Manager, Freehold Resources, the trustee of the Share Trust and the Trustee as trustee for and on behalf of the Trust, the Unitholders will be entitled to attend all meetings of shareholders of Freehold Resources and except as set forth below, to direct

the manner in which the Share Trust will vote its shares in Freehold Resources at all such meetings. Prior to the Share Trust voting its shares in Freehold Resources each Unitholder shall be entitled to vote in respect of the matter on the basis of one vote per Trust Unit held, and the Share Trust shall be required to vote its shares in Freehold Resources in accordance with the result of the vote of the Unitholders. Unitholders shall be entitled to direct the Share Trust as to how to vote in respect of all matters placed before the shareholders of Freehold Resources including, in respect of matters relating to the election of the directors of Freehold Resources (other than the directors of Freehold Resources to be elected by the Manager pursuant to the terms of the Unanimous Shareholder Agreement, which is currently two), approving its financial statements and appointing auditors of Freehold Resources. In addition, Unitholders will be entitled to direct the Share Trust as to how to vote its shares in Freehold Resources on any proposed amendment to the Unanimous Shareholder Agreement, where such amendment is required to be approved by Special Resolution. The Share Trust will not be entitled, without the direction of Unitholders, to exercise its rights as shareholder of Freehold Resources except as set forth above.

The Unanimous Shareholder Agreement provides that the board of directors of Freehold Resources shall consist of a minimum of five and a maximum of nine directors, and that the Unitholders will be entitled to elect a majority of the board of directors of Freehold Resources and the Manager will be entitled to elect the balance of the directors. The number of directors is currently set at seven.

The Unanimous Shareholder Agreement also provides that Freehold Resources will be prohibited from making payment of dividends on its shares.

Decision Making

Although the Manager provides certain advisory and management services to the Trust and Freehold Resources pursuant to the Management Agreement, the board of directors of Freehold Resources supervises the management of the business and affairs of the Trust and Freehold Resources. In particular, significant operational decisions and all decisions relating to: (a) issuances of additional Trust Units; (b) the acquisition and disposition of properties of the Trust or Freehold Resources for a purchase price or proceeds in excess of \$5.0 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities; and (e) the payment of Distributions to Unitholders, will be made by the board of directors of Freehold Resources. Any amendment to the Management Agreement or the Freehold Resources Royalty Agreement requires the approval of the board of directors of Freehold Resources on behalf of the Trust. The board of directors of Freehold Resources has held regularly scheduled meetings to review the business and affairs of Freehold Resources and make any necessary decisions relating thereto.

Board of Directors of Freehold Resources

Freehold Resources has a board of directors consisting of seven individuals, two of whom have been elected by the Manager and five of whom are independent directors. Four of the five independent directors have been elected by the Unitholders. The Chairman of the board of directors is one of the independent directors.

The name, municipality of residence, position held and principal occupation of each director and officer of Freehold Resources are set out below:

Name and Municipality of Residence	Position with Freehold Resources	Principal Occupation	Director/ Officer Since	Number of Trust Units Held
William W. Siebens ⁽²⁾⁽⁴⁾ Calgary, Alberta	Chairman and Director	President and Chief Executive Officer, Candor Investments Ltd. (private energy and investment corporation)	July 29, 1996	50,000
David J. Sandmeyer ⁽⁵⁾ Calgary, Alberta	Director, President and Chief Executive Officer	President of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	17,000 ⁽⁶⁾
D. Nolan Blades ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Calgary, Alberta	Director	President, Sunny Gables Holdings Ltd. (private holding company)	July 29, 1996	30,000
Harry S. Campbell, Q.C. ⁽³⁾⁽⁴⁾ Calgary, Alberta	Director	Managing Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	July 29, 1996	2,800

Name and Municipality of Residence	Position with Freehold Resources	Principal Occupation	Director/ Officer Since	Number of Trust Units Held
Tullio Cedraschi ⁽⁵⁾ Montreal, Quebec	Director	President and Chief Executive Officer, CN Investment Division (manages the pension funds for employees of the Canadian National Railway Company)	January 21, 1998	nil ⁽⁶⁾
Peter T. Harrison ⁽¹⁾⁽³⁾⁽⁴⁾ Brossard, Quebec	Director	Senior Vice-President, Montrusco Bolton Inc. (investment counsel)	July 29, 1996	22,000
Dr. P. Michael Maher ⁽¹⁾⁽²⁾⁽⁴⁾ Calgary, Alberta	Director	Professor, Haskayne School of Business, University of Calgary	July 29, 1996	1,000
J. Frank George Calgary, Alberta	Vice-President, Exploitation	Vice President, Exploration of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	nil ⁽⁶⁾
Darren G. Gunderson Calgary, Alberta	Controller	Controller, Freehold Resources Ltd. (private oil and gas exploitation and production company)	November 13, 2003	nil ⁽⁶⁾
Joseph N. Holowisky Calgary, Alberta	Vice-President, Finance & Administration, Chief Financial Officer and Secretary	Vice-President, Finance & Administration and Secretary of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	nil ⁽⁶⁾
William O. Ingram Calgary, Alberta	Vice-President, Production	Vice-President, Production of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	nil ⁽⁶⁾
Michael J. Okrusko Calgary, Alberta	Vice-President, Land	Vice-President, Land of Rife Resources Ltd. (private oil and gas exploration and production company)	July 29, 1996	1,000 ⁽⁶⁾

Notes:

- (1) Member of Audit Committee.
- (2) Member of Corporate Governance & Nominating Committee.
- (3) Member of Reserves Committee.
- (4) Independent directors of Freehold Resources who were elected by the Unitholders at the last Annual meeting of the Trust on May 5, 2004.
- (5) Nominees of the Manager.
- (6) CN Pension Trust Funds, including the Trust Units owned by the Manager, owns 9,914,536 Trust Units (31.49%) of the Trust as at May 10, 2004. The Manager, which is a wholly owned subsidiary of Rife, owns 616,736 Trust Units as at May 10, 2004. Rife is 100% owned by the CN Pension Trust Funds.

Each of the directors has been engaged in his principal occupation or in other capacities with the same firm or organization for the past five years except for: D. Nolan Blades who, until April 13, 2000 was President and Chief Executive Officer of Pursuit Resources Corporation.

As at May 10, 2004, the directors and senior officers of Freehold Resources, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 123,800 Trust Units or less than 0.4% of the issued and outstanding Trust Units.

The following is a brief description of the backgrounds of the directors and officers of Freehold Resources:

William W. Siebens

Mr. Siebens brings special expertise to Freehold Resources with his knowledge of the Trust's royalty lands as a portion of these lands were previously owned by Siebens Oil & Gas Ltd. Mr. Siebens is President and Chief Executive Officer of Candor Investments Ltd. (Calgary), a private energy and investment corporation. He currently serves on the boards of Petro-Canada and The Fraser Institute.

David. J. Sandmeyer

Mr. Sandmeyer is President, Chief Executive Officer and a director of Freehold Resources and President of Rife (Calgary). Prior to joining Rife, he held senior positions with Amoco Canada Petroleum Company Limited for 18 years. He is a former Governor of the Canadian Association of Petroleum Producers. A graduate of the University of Saskatchewan, he holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer.

D. Nolan Blades

Mr. Blades is President of Sunny Gables Holdings Ltd. (Calgary) and a Professional Engineer with extensive experience in the oil and gas industry. Mr. Blades has held senior positions with Kaiser Oil Ltd., Oakwood Petroleum Ltd. and Chauvco Resources Ltd. and most recently was President and Chief Executive Officer of Pursuit Resources Corp.

Harry S. Campbell

Mr. Campbell is Managing Partner of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974. Mr. Campbell is currently a Director of Delphi Energy Corp. and The Cathay Investment Fund Limited and has been a director of numerous private and public corporations.

Tullio Cedraschi

Mr. Cedraschi is President and Chief Executive Officer of the CN Investment Division (Montreal). He is currently a director of the Toronto Stock Exchange, and serves on the boards of several corporations. He is a Governor and Past President of the National Theatre School of Canada and he is also a Governor of McGill University where he received his MBA.

Peter T. Harrison

Mr. Harrison is Senior Vice-President of Montrusco Bolton Inc. (Montreal). Mr. Harrison has over 24 years of investment experience and most recently managed Canadian Equities for the CN Investment Division. He holds a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario and is a Chartered Financial Analyst.

Dr. P. Michael Maher

Dr. Maher is a Professor and former Dean of the Haskayne School of Business of the University of Calgary and has served on the boards of numerous corporations and public sector organizations. He has a Bachelor of Engineering degree, University of Saskatchewan; an MBA, University of Western Ontario; a Ph.D. from Northwestern University; a Doctor of Commerce (honoris causa) degree from St. Mary's and is a Professional Engineer.

J. Frank George

Mr. George, Vice President, Exploitation of the Manager (Calgary), joined Rife in 1983 as Chief Geologist and became Vice President, Exploration in 1994. He is responsible for the management and coordination of all exploration and geological evaluation activities of Rife. In 1996 he was appointed Vice President Exploitation of Freehold Resources. A graduate of the University of Calgary, Mr. George is a registered Professional Geologist in Alberta and a member of the Canadian Society of Petroleum Geologists.

Darren G. Gunderson

Mr. Gunderson, Controller of Freehold Resources (Calgary), joined Rife in 1991 in the accounting department and became Controller in 1999. Mr. Gunderson holds a Bachelor of Commerce degree from the University of Saskatchewan and is a Certified General Accountant.

Joseph N. Holowisky

Mr. Holowisky, Vice President Finance and Administration, Secretary and a director of the Manager (Calgary), joined Canpar in 1982 as Audit Manager. In 1985, Mr. Holowisky was appointed Manager, Accounting and Audit for both Canpar and Rife. He is currently Vice President, Finance and Administration, Chief Financial Officer and Secretary for both companies, and also of Freehold Resources. Mr. Holowisky is a member of the Petroleum Accounting Society of Canada and the Institute of Internal Auditors. Mr. Holowisky serves on the Executive Committee of the Advisory board of directors of the Canadian Petroleum Insurance Exchange and is Chairman of the board of directors of the Canadian Petroleum Insurance Exchange Ltd.

William O. Ingram

Mr. Ingram joined Rife (Calgary) in 1984. As Vice-President, Production, of each of Rife and the Manager, Mr. Ingram is responsible for production and drilling operations, marketing, acquisitions, reserve analysis and economic evaluations. His appointment as Vice-President, Production of Freehold Resources was effective with the start-up of the Trust in November 1996. Mr. Ingram is a Professional Engineer and holds a B.Sc. degree in Chemical Engineering from the University of Alberta. He is a member of The Association of Professional Engineers, Geologists and Geophysicists of Alberta (APPEGA).

Michael J. Okrusko

Mr. Okrusko, Vice President, Land, joined Rife (Calgary) and Canpar in October 1982 as Manager of Land. His appointment as Vice-President, of Freehold Resources was effective with the start-up of the Trust in November 1996. Mr. Okrusko is a graduate of the Southern Alberta Institute of Technology (Petroleum Technology) and holds a B. Commerce (Finance) degree from the University of Calgary. Mr. Okrusko is an active member of the Canadian Association of Petroleum Landman and has obtained the P. Land designation.

Audit Committee

Mandate

Role and Objective

The Audit Committee (the "Committee") is a committee of the board of directors of Freehold Resources to which the board has delegated certain responsibilities for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to Freehold Resources and the Trust (hereinafter collectively referred to as "Freehold"), are as follows:

1. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Freehold and related matters;
2. To provide better communication between directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the transparency, credibility and objectivity of financial reporting; and
5. To strengthen the role of the outside directors by facilitating in-depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of Freehold Resources, all of whom are “independent” (as such term is used in Multilateral Instrument 52-110 – Audit Committees (“MI 52-110”).
2. The board of directors shall have the power to appoint the Committee Chairman.
3. All of the members of the Committee shall be “financially literate”. The board of directors of Freehold Resources has adopted the definition for “financial literacy” used in MI 52-110.

Meetings

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the chairman of the meeting shall not be entitled to a second or deciding vote.
2. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the board.
3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
4. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.
5. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements) and at such other times as the external auditor and the Committee consider appropriate.
6. The Committee shall meet with the external reserve evaluators at least once per year (in connection with the preparation of the year end reserves).

Mandate and Responsibilities of Committee

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.
2. It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to Freehold’s internal control systems:
 - identifying, monitoring and mitigating business risks; and
 - ensuring compliance with legal, ethical and regulatory requirements.
3. It is a primary responsibility of the Committee to review the annual financial statements of Freehold prior to their submission to the board of directors for approval. The process should include but not be limited to:
 - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years’ financial statements;
 - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
 - reviewing accounting treatment of unusual or non-recurring transactions;
 - reviewing the Trust’s status as a “mutual fund trust” under the *Income Tax Act* (Canada);
 - ascertaining compliance with covenants under loan agreements and Trust Indenture;
 - reviewing adequacy of the reclamation fund;
 - reviewing disclosure requirements for commitments and contingencies;

- reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
 - reviewing unresolved differences between management and the external auditors; and
 - obtaining explanations of significant variances with comparative reporting periods.
4. The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of Freehold's disclosure of all other financial information and shall periodically access the accuracy of those procedures.
 5. With respect to the appointment of external auditors by the board, the Committee shall:
 - recommend to the board the appointment of external auditors;
 - recommend to the board the terms of engagement of the auditor, including the compensation of the auditors and confirmation that the auditors shall report directly to the Committee;
 - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
 - review and approve any non-audit services to be provided by the auditors' firm and consider the impact on the independence of the auditors.
 6. The Committee shall review with external auditors (and internal auditor if one is appointed by Freehold) their assessment of the internal controls of Freehold, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their audit plan and, upon completion of the audit, their reports upon the financial statements of Freehold and its subsidiaries.
 7. The Committee must pre-approve all non-audit services to be provided to Freehold or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.
 8. The Committee shall review on an annual basis the reserves as evaluated by the external reserve evaluators. This annual process shall include a face-to-face meeting with management and the reserve evaluators.
 9. The Committee shall review risk management policies and procedures of Freehold (i.e. hedging, litigation and insurance).
 10. The Committee shall review and approve management's hiring policies regarding current and former partners and employees of the present and former external auditor.
 11. The Committee shall establish a procedure for:
 - the receipt, retention and treatment of complaints received by Freehold regarding accounting, internal accounting controls or auditing matters; and
 - the confidential, anonymous submission by employees of Freehold of concerns regarding questionable accounting or auditing matters.
 12. The Committee shall have the authority to investigate any financial activity of Freehold. All employees of Rife are to cooperate as requested by the Committee.
 13. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Freehold without any further approval of the board.

Composition of Audit Committee

Freehold's audit committee consists of Mr. D. Nolan Blades (Chair), Mr. Peter T. Harrison and Dr. P. Michael Maher. All members of the audit committee are independent and financially literate. See "Corporate Governance - Board of Directors of Freehold Resources".

External Auditor Service Fees

	Year ended December 31	
	2003	2002
Audit fees	\$ 33,150.00	\$ 60,905.00
Audit-related fees	-	-
Tax fees	2,750.00	5,215.00
All other fees ⁽¹⁾	975.00	-
Total	\$ 36,875.00	\$ 66,120.00

Notes:

(1) Fees for professional services rendered in respect to review and discussions relating to the Trust's renegotiation of its long-term debt facility.

THE MANAGER

The Manager is a wholly-owned subsidiary of Rife, which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of the Canadian National Railway Company).

Management Agreement

Freehold Resources and the Trustee, as trustee for and on behalf of the Trust, entered into the Management Agreement with the Manager, pursuant to which Freehold Resources and the Trust engaged the Manager for an initial term of five years, which initial term has automatically renewed for an additional three year term expiring in November, 2004, to:

- a. manage the Trust, subject to the supervision of Freehold Resources;
- b. administer all matters relating to the HB Lands Royalties, Additional Royalties, Freehold Resources Royalty and Trust Units, including: (i) determining the total amount owing to the Trust and Freehold Resources from third parties and conducting joint venture audits as required; (ii) determining the total amounts owing to Unitholders and arranging for Distributions to Unitholders, subject to the supervision of Freehold Resources; (iii) providing Unitholders with periodic reports on the HB Lands Royalties, Additional Royalties, Freehold Resources Royalty and the Freehold Resources Properties; and (iv) providing Unitholders with financial reports and tax information relating to the HB Lands Royalties, Additional Royalties, Freehold Resources Properties and the Freehold Resources Royalty;
- c. provide management services for the economic and efficient exploitation of oil and natural gas properties;
- d. operate oil and natural gas properties which Freehold Resources is entitled to operate and monitor the activities of third party operators;
- e. recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for the Trust and Freehold Resources;
- f. negotiate on behalf of Freehold Resources all exploitation and development agreements, operating agreements, working agreements, farmin and farmout agreements, leases and other documents relating to the exploitation of the oil and natural gas properties as may be advisable;
- g. recommend and, subject to the supervision of Freehold Resources, negotiate banking arrangements for the Trust and Freehold Resources; and
- h. provide office space, office furnishings and equipment and personnel necessary for the proper administration of the assets of the Trust and Freehold Resources.

The Management Agreement will be renewed for successive three year terms following the end of its current three year term unless the termination of the Management Agreement at the end of a term has been approved by a Special Resolution of Unitholders and the Manager is given 12 months written notice of termination or unless the Trustee is given 12 months written notice of termination by the Manager prior to the end of a term.

Proceeds relating to subscription offerings, Royalty Income and any cash flow and other revenues generated from or associated with any interest of the Trust in the HB Lands Royalties, the Additional Royalties or the Freehold Resources Royalty, or of Freehold Resources in the Freehold Resources Properties may not be commingled with the funds of any other entity which is managed by the Manager.

The Manager is paid Management Fees for providing all of the management services. The Manager will be indemnified by Freehold Resources in respect of certain damages which it may suffer in discharging its obligations under the Management Agreement provided that such damages do not arise from the fraud, willful default, gross negligence or bad faith of the Manager.

The board of directors of Freehold Resources and the Trustee will review on an ongoing basis both the nature and extent of the services required of the Manager and the costs of providing the same. All amendments to the Management Agreement must be approved by a majority of the independent members of the board of directors of Freehold Resources and the Trustee, upon the recommendation of Freehold Resources and the Manager.

Compensation

The Manager will be compensated as follows for providing services to the Trust and Freehold Resources.

Management Fees

Pursuant to the Management Agreement, the Manager receives a Management Fee, paid in Trust Units, based on the number of issued and outstanding Trust Units at the end of each quarter. The quarterly Management Fee was initially 20,000 Trust Units. The Management Fee is adjusted, based on the total issued and outstanding Trust Units, so that the quarterly Management Fee is in the same proportion as 20,000 was to the outstanding Trust Units on November 25, 1996, excluding Trust Units issued as a Management Fee. The issuance of 3.3 million Trust Units in May 2001 resulted in a pro-rata increase in the management fee to 22,500 Trust Units per quarter in accordance with the Management Agreement.

During 2003, the Manager received 90,000 Trust Units as the Management Fee to the Manager, bringing the total number of units received by the Manager to 594,236 from inception of the Trust in late 1996 to December 31, 2003.

General and Administrative Costs

The Manager is reimbursed for General and Administrative Costs incurred on behalf of the Trust. General and Administrative Costs are deducted in computing Freehold Resources Royalty Income to the extent not paid from the residual income of Freehold Resources. General and Administrative Costs are generally charged to Freehold Resources and the Trust by the Manager based on time spent and direct costs incurred in fulfilling the obligations of the Manager to Freehold Resources and the Trust pursuant to the Management Agreement. The Manager charged the Trust \$2.3 million for General and Administrative Costs for the year ended December 31, 2003.

Acquisition and Disposition Fees

The Manager is paid an acquisition fee equal to 1.5% of the purchase price of any Additional Royalties purchased by the Trust or any Additional Properties acquired by Freehold Resources. In the case of property exchanges or swaps, the Manager will receive the 1.5% acquisition fee up to the purchase price of the properties acquired. No fees will be payable with respect to the proceeds of disposition of any HB Lands Royalties, Additional Royalties or Freehold Resources Properties. The Manager did not receive any acquisition fees for the acquisition of the HB Lands Royalties or the Working Interest Properties. During 2003, \$52,000 (2002 - \$38,000) was paid related to acquisitions. This fee is charged to capital assets as part of the properties acquired.

Directors and Officers of the Manager

The name, municipality of residence, position held and principal occupation of each director and officer of the Manager are set out below:

Name and Municipality of Residence	Position with the Manager	Principal Occupation	Director/ Officer Since	Number of Trust Units Held
David J. Sandmeyer Calgary, Alberta	President and Director	President of Rife Resources Ltd.	October 1, 1996	17,000
J. Frank George Calgary, Alberta	Vice-President Exploitation	Vice-President, Exploration of Rife Resources Ltd.	October 1, 1996	nil
Joseph N. Holowisky Calgary, Alberta	Vice-President, Finance and Administration, Secretary and Director	Vice-President, Finance and Administration and Secretary of Rife Resources Ltd.	October 1, 1996	nil
William O. Ingram Calgary, Alberta	Vice-President, Production	Vice-President, Production of Rife Resources Ltd.	October 1, 1996	nil
Michael J. Okrusko Calgary, Alberta	Vice-President, Land	Vice-President, Land of Rife Resources Ltd.	October 1, 1996	1,000

As at May 10, 2004 the directors and senior officers of the Manager, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 18,000 Trust Units. Rife owns 100% of the outstanding shares in the capital of the Manager. All of the shares of Rife are owned by the CN Pension Trust Funds.

There were no amounts paid by Freehold Resources or the Trust to any person set forth above during the period ended December 31, 2003.

The following is a brief description of the backgrounds of the directors and officers of the Manager:

David. J. Sandmeyer

Mr. Sandmeyer is President, Chief Executive Officer and a director of Freehold Resources and President of Rife (Calgary). Prior to joining Rife, he held senior positions with Amoco Canada Petroleum Company Limited for 18 years. He is a former Governor of the Canadian Association of Petroleum Producers. A graduate of the University of Saskatchewan, he holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer.

J. Frank George

Mr. George, Vice President, Exploitation of the Manager (Calgary), joined Rife in 1983 as Chief Geologist and became Vice President, Exploration in 1994. He is responsible for the management and coordination of all exploration and geological evaluation activities of Rife. In 1996 he was appointed Vice President Exploitation of Freehold Resources. A graduate of the University of Calgary, Mr. George is a registered Professional Geologist in Alberta and a member of the Canadian Society of Petroleum Geologists.

Joseph N. Holowisky

Mr. Holowisky, Vice President Finance and Administration, Secretary and a director of the Manager (Calgary), joined Canpar in 1982 as Audit Manager. In 1985, Mr. Holowisky was appointed Manager, Accounting and Audit for both Canpar and Rife. He is currently Vice President, Finance and Administration, Chief Financial Officer and Secretary for both companies, and also of Freehold Resources. Mr. Holowisky is a member of the Petroleum Accounting Society of Canada and the Institute of Internal Auditors. Mr. Holowisky serves on the Executive Committee of the Advisory board of directors of the Canadian Petroleum Insurance Exchange and is Chairman of the board of directors of the Canadian Petroleum Insurance Exchange Ltd.

William O. Ingram

Mr. Ingram joined Rife in 1984. As Vice-President, Production, of each of Rife and the Manager (Calgary), Mr. Ingram is responsible for production and drilling operations, marketing, acquisitions, reserve analysis and economic evaluations. His appointment as Vice-President, Production of Freehold Resources was effective with the start-up of the Trust in November 1996. Mr. Ingram is a Professional Engineer and holds a B.Sc. degree in Chemical Engineering from the University of Alberta. He is a member of The Association of Professional Engineers, Geologists and Geophysicists of Alberta (APPEGA).

Michael J. Okrusko

Mr. Okrusko, Vice President, Land, joined Rife and Canpar (Calgary) in October 1982 as Manager of Land. His appointment as Vice-President, of Freehold Resources was effective with the start-up of the Trust in November 1996. Mr. Okrusko is a graduate of the Southern Alberta Institute of Technology (Petroleum Technology) and holds a B. Commerce (Finance) degree from the University of Calgary. Mr. Okrusko is an active member of the Canadian Association of Petroleum Landman and has obtained the P. Land designation.

Business of the Manager

The Manager was established to provide comprehensive oil and gas company management and operational services to the Trust and Freehold Resources. The Manager is a wholly-owned subsidiary of Rife. Pursuant to an agreement between Rife and the Manager dated November 25, 1996, Rife provides the Manager, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to the Trust and Freehold Resources on a cost recovery basis.

CONFLICTS OF INTEREST

There may be situations in which the interests of the Manager will conflict with those of Unitholders. As part of the ordinary course of business of the Manager, the Manager may continue to acquire oil and natural gas properties on its own behalf and on behalf of persons other than the Unitholders. The Manager may manage and administer such additional properties, as well as enter into other types of energy-related management, advisory and investment activities. Thus neither the Manager, nor its management, will carry on their full-time activities on behalf of Unitholders and, when acting on its own behalf or on behalf of others, may at times act in contradiction to or competition with the interests of Unitholders.

In resolving such conflicts, decisions will be made by the Manager on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties all consistent with the duties of the Manager to each such group of persons. The Management Agreement contains provisions which require the Manager to make disclosure to the board of directors of Freehold Resources of the fact and substance of any particular conflict of interest and to use all reasonable efforts to resolve such conflicts of interest in a manner which will treat the Trust or Freehold Resources, as the case may be, and the other interested party fairly taking into account all of the circumstances of the Trust or Freehold Resources, as the case may be, and such interested party and to act honestly and in good faith in resolving such matters.

Although the Manager provides advisory and management services to Freehold Resources, the board of directors of Freehold Resources supervises the management of the business and affairs of Freehold Resources. The board makes significant operational decisions and all decisions relating to: (i) the issuance of additional Trust Units; (ii) the acquisition and disposition of properties for a purchase price or proceeds in excess of \$5.0 million; (iii) the approval of capital expenditure budgets; (iv) the establishment of credit facilities; and (v) the determination of the amount of Distributions to Unitholders.

Circumstances may arise where members of the board of directors of Freehold Resources serve as directors or officers of corporations which are in competition to the interests of Freehold Resources and the Trust. No assurances can be given that opportunities identified by such board members will be provided to Freehold Resources and the Trust.

INDUSTRY INFORMATION

Government Regulation

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and gas industry. It is not expected that any of such controls or regulations would affect the operations of the Trust or Freehold Resources in a manner materially different than they would affect other companies of similar size in the oil and gas industry. All current legislation is a matter of public record and the Trust is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing

Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, the value of the refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board ("NEB"). Any oil export to be made pursuant to a contract of longer duration requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

Natural Gas

In Canada, the price of natural gas sold is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the government of Canada. As is the case with oil, natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB license and Governor in Council approval. The price received by the Trust and Freehold Resources depends, in part, on the prices of competing natural gas and other substitute fuels, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply and demand balance and other contractual terms.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada - U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed provided that the restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade and then only if the export restrictions do not:

- (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36 month period),
- (ii) impose an export price higher than the domestic price, and
- (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Royalties and Incentives

In addition to federal regulation, the provinces of Alberta, Saskatchewan, British Columbia and Manitoba have legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on the prescribed reference prices, well productivity, geographical location, field discovery date, the method of recovery and the type or quality of the petroleum product produced.

From time to time, the provincial governments of Canada have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced production projects.

Oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid by the Freehold Resources to governments. These incentives increase the net income of the Trust and Freehold Resources.

There are no assurances that the government's programs or other incentives currently in place will remain so. The termination of any of the current incentives may have a significant effect upon the Trust and the amount of Distributions to Unitholders.

Alberta Royalty Credits

The entitlement to Alberta Royalty Credits (ARC is based on the payment of Alberta Crown royalties in respect of properties located in Alberta.) The HB Land Royalties held by the Trust are not eligible for ARC because no Alberta Crown royalties are paid by the Trust in respect to revenue received from the HB Lands. The original Working Interest Properties acquired by Freehold Resources from each of Canpar and Rife are also not eligible for ARC. Canpar and Rife are associated corporations and were "restricted corporations" (at the maximum credit limit) at the time of disposing of the Working Interest Properties. Consequently, these interests became "restricted resource properties" to Freehold Resources. Royalties on production attributed to these interests are excluded from Alberta Crown royalties for ARC purposes. However, wells drilled and completed in Alberta on lands acquired from Canpar and Rife, subsequent to their acquisition by Freehold Resources, are entitled to ARC with respect to Alberta Crown royalties paid on production from these wells.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and gas industry operations and can affect the location of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders. Environmental legislation in Alberta has undergone a major revision and has been consolidated into the Environmental Protection and Enhancement Act. Under the new Act, environmental standards and compliance for releases, clean-up and reporting are stricter. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes will have an incremental effect on the cost of conducting operations in Alberta. British Columbia's Environmental Assessment Act became effective June 30, 1995. This legislation rolled the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process.

Freehold Resources is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment. Freehold Resources' internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding. The Manager believes that Freehold Resources is in material compliance with applicable environmental laws and regulations with respect to the Freehold Resources Properties.

With respect to the HB Lands, the responsibilities for adherence to environmental regulations reside with the operators and working interest owners of the HB Lands and not with the Trust.

MARKET FOR SECURITIES

The Trust Units are listed on The Toronto Stock Exchange ("TSX") and commenced trading on November 25, 1996. The trading symbol for the Trust Units is FRU.UN.

The following table sets forth the price range and trading volume of the Trust Units as reported by the TSX for the periods indicated.

Date	Open (\$)	High (\$)	Low (\$)	Close (\$)	Volume Traded
2003					
January	10.90	11.20	10.50	11.18	772,258
February	11.20	11.85	11.07	11.78	632,437
March	11.70	11.85	10.50	11.78	1,620,403
April	11.61	11.90	11.20	11.65	858,767
May	11.60	12.95	11.50	12.84	839,746
June	12.73	13.48	12.51	13.05	748,672
July	13.13	13.30	12.90	13.25	984,472
August	13.25	13.61	13.10	13.35	662,910
September	13.40	13.85	12.81	13.70	1,343,931
October	13.80	13.98	13.24	13.29	544,411
November	13.45	15.25	13.11	15.25	749,061
December	15.25	17.19	15.10	16.35	1,212,870
2004					
January	16.30	16.30	14.52	15.19	850,297
February	15.50	15.60	14.02	14.81	760,334
March	14.85	15.49	14.37	14.75	788,283
April	14.95	15.80	14.65	15.39	419,684
May 1-10	15.25	15.75	15.15	15.42	625,490

LEGAL PROCEEDINGS

There are no outstanding legal proceedings which are for claims in excess of 10% of the current Asset Value of the Trust to which the Trust is a party or in respect of which any of its properties are subject, nor are there any such proceedings pending or known to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

On February 25, 2003, the Manager exercised previously granted options to acquire 1,000,000 Trust Units. The proceeds of this exercise of \$9.2 million was used to pay down bank debt. The Manager is a wholly-owned subsidiary of the CN Pension Trust Funds, which now holds 9,914,536 Trust Units as at May 10, 2004, representing 31.49 percent of the outstanding Trust Units.

There were no material interests, direct or indirect, of any directors or executive officers of the Manager, directors or executive officers of Freehold Resources, any Unitholder who beneficially owns more than 10% of the Trust Units or any known associate or affiliate of such persons in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Trust, other than as disclosed herein.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Trust are KPMG LLP, Chartered Accountants, Calgary, Alberta.

Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Trust Units.

MATERIAL CONTRACTS

Except for contracts entered into since January 1, 2002, by the Trust in the ordinary course of business or otherwise disclosed herein, the only material contracts entered into or to be entered into by the Trust which is considered material is the Amended and Restated Trust Indenture dated May 1, 2002 as described under the heading "Trust Units – The Trust Indenture".

INTERESTS OF EXPERTS

The Trimble Report, wherein is summarized in this AIF, was prepared by Trimble and certified in the form attached hereto in Appendix A. KPMG LLP are the auditors of the Trust and have prepared a report as the audited financial statements of the Trust for the year ended December 31, 2003.

No person or company whose profession or business gives authority to a statement made by such person or company and who is named in this AIF as having prepared or certified a part of this AIF, or a report or valuation described in this AIF or in a document specifically incorporated by reference into this AIF, has received or shall receive a direct or indirect interest in the property of the Trust or of any associate or affiliate of the Trust. As at the date hereof, the aforementioned persons and companies beneficially own, directly or indirectly, less than 1% of the securities of the Trust and its associates and affiliates. In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Trust or of any associates or affiliates of the Trust.

ADDITIONAL FINANCIAL AND OTHER INFORMATION

Additional information about the Trust may be found on SEDAR at www.sedar.com. Information about remuneration and indebtedness of directors and officers of Freehold Resources and the Manager, principal holders of the Trust Units and options to purchase Trust Units, is contained in the Information Circular – Proxy Statement of the Trust dated March 16, 2004 which relates to the Annual Meeting of Unitholders held on May 5, 2004. Additional financial information is provided in the combined financial statements of the Trust and Freehold Resources for the period ended December 31, 2003 and the accompanying Management's Discussion and Analysis.

The Trust shall provide to any person, upon request to the Manager on behalf of the Trust:

- a. when the securities of the Trust are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities,
 - (i) one copy of the Annual Information Form of the Trust, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form,
 - (ii) one copy of the combined financial statements of the Trust and Freehold Resources for the period ended December 31, 2003 together with the accompanying report of the auditor and one copy of any subsequent interim financial statements,
 - (iii) one copy of the Information Circular – Proxy Statement of the Trust dated March 16, 2004, and
 - (iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above;
- b. at any other time, one copy of any other documents referred to in (a) (i), (ii) and (iii) above, provided the Trust may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the Trust.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

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

APPENDIX A

Report on Reserves Data by Independent Qualified Reserves Evaluator

To the board of directors of Freehold Resources Ltd. and Rife Resources Management Ltd., as manager of Freehold Royalty Trust (the "Trust"):

1. We have evaluated the Trust's reserves data as at December 31, 2003. The reserves data consist of the following:
 - (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and
 - (ii) the related estimated future net revenue; and
 - (b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and
 - (ii) the related estimated future net revenue.
2. The reserves data are the responsibility of the Trust's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Trust evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have evaluated and reported on to the Trust's management.

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
Trimble Engineering Associates Ltd.	January 1, 2004	Canada	nil	\$255,791,000	nil	\$255,791,000

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after its preparation date.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Calgary, Alberta / Canada, February 19, 2004
Trimble Engineering Associates Ltd.

"signed"

Stephen C. Trimble, P.Eng.
President

APPENDIX B

Report of Management and Directors on Reserves Data and Other Information

Management of Freehold Royalty Trust (the "Trust") being Freehold Resources Ltd. ("Resources") is responsible for the preparation and disclosure of information with respect to oil and gas activities of Trust in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

- (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and
- (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and
- (ii) the related estimated future net revenue.

An independent qualified reserves evaluator, Trimble Engineering Associates Ltd. ("Trimble"), has evaluated the Trust's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of Resources has:

- (a) reviewed the Trust's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with Resources and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors of Resources has reviewed the Trust's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors of Resources has, on the recommendation of the Reserves Committee, approved:

- (a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Dated at Calgary, Alberta, this 30th day of March, 2004

"signed"

David J. Sandmeyer, P.Eng.
President and CEO and Director

"signed"

D. Nolan Blades, P. Eng.
Director and Chair, Reserves Committee

"signed"

William O. Ingram
Vice-President, Production

"signed"

Peter T. Harrison
Director and Member, Reserves Committee